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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies	R.06-04-009

NOTICE OF EX PARTE COMMUNICATION

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June 4, 2007

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OF THE STATE OF CALIFORNIA

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NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the Cogeneration Association of California[1] and the Energy Producers and Users Coalition[2] (jointly CAC/EPUC), submit this notice.

On May 30, 2007, Evelyn Kahl, counsel to CAC/EPUC, distributed through courier service, a report entitled "CHP Policy Assistance" compiled by Delta Energy and Environment, consultants to CAC/EPUC. The report which is attached was sent to the following:

Michael Peevey
Timothy Simon
John Bohn
Rachelle Chong
Dian Grueneich
Nancy Ryan
Jaclyn Marks
Stephen St. Marie
Andrew Campbell

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1 CAC represents the power generation, power marketing and cogeneration operation interests of the following entities: Coalinga Cogeneration Company, Mid-Set Cogeneration Company, Kern River Cogeneration Company, Sycamore Cogeneration Company, Sargent Canyon Cogeneration Company, Salinas River Cogeneration Company, Midway Sunset Cogeneration Company and Watson Cogeneration Company.

2 EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP West Coast Products LLC, Chevron U.S.A. Inc., ConocoPhillips Company, ExxonMobil Power and Gas Services Inc., Shell Oil Products US, THUMS Long Beach Company, Occidental Elk Hills, Inc., and Valero Refining Company - California

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Dated: June 4, 2007

Respectfully submitted,

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Evelyn Kahl

Counsel to
the Energy Producers and Users Coalition
and the Cogeneration Association of California

CHP Policy Assistance
-
A Report for
The Energy Producers and Users Coalition
and
The Cogeneration Association of California

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Acronyms

BAT	Best Available Technology
CAIR	Clean Air Interstate Rule
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
CHPQA	CHP Quality Assurance
EERE	Energy Efficiency / Renewable Energy
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
ERA	Early Reduction Allowance
ETS	Emissions Trading Scheme
EU	European Union
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
ISO	Independent System Operator (grid operator)
MOU	Memorandum of Understanding
NAP	National Allocation Plan
NATS	NOx Allowance Tracking System
NER	New Entrant Reserve
PES	Primary Energy Saving
PURPA	Public Utilities Regulatory Policy Act
RGGI	Regional Greenhouse Gas Initiative
ROC	Renewable Obligation Certificate
SIP	State Implementation Plan
t	A metric tonne (1,000 kg)
WADE	World Alliance for Decentralized Energy

Executive Summary

Combined heat and power (CHP) is increasingly recognized as one of the most proven, cost-effective and reliable means of reducing carbon emissions and increasing fossil fuel efficiency in the power and heat sectors. For example, CHP can reduce CO_2 emissions by 20-25% in comparison with separate generation by state-of-the-art CCGT and boiler plants.

There is, accordingly, growing experience around the world of governments and regulators seeking to both remove barriers to CHP and introduce incentives to its wider development. A critical aspect of these efforts lies with the proper characterization of CHP in emissions trading systems. Consequently, the primary objective of this report is to explore the treatment of CHP in emissions trading systems, including the European Union Emissions Trading Scheme (EU ETS), the Regional Greenhouse Gas Initiative (RGGI) and the US Clean Air Interstate Rule (CAIR). This report describes the range of alternatives that have been considered in these systems and highlights the most effective options in encouraging CHP development.

Beyond emissions trading, this report addresses broader policy initiatives aimed to encourage CHP development. A handful of countries in Europe, most notably the Netherlands, Finland and Denmark, have developed specific policy programmes designed to ensure that CHP can provide a substantial overall share of electricity generation – a level that exceeds 30% in each case. This report describes some of the most effective measures that have been adopted to accelerate CHP market development, including various forms of policy and fiscal support. It also highlights areas in which regulation has fallen short of its intended goals.

This report is intended to provide an overview of CHP treatment in various regulatory frameworks. It offers no recommendation at this time concerning the specific mechanisms that should be employed in the development of California's greenhouse gas regulations under Assembly Bill 32. Also, the information presented in this report concerning emissions trading systems must be placed in context. To date, the only experience with the regulation of greenhouse gasses and other pollutants are systems in which the regulation occurs at the emissions source. The experience gained in a source-based system may not be fully transferable to a GHG regulation system where the emissions are regulated further downstream, such as the load-based system under study for the California electricity sector. Likewise, the systems reviewed in this report involve emissions trading markets; design elements and lessons learned from these systems would have little relevance in the development of a system where active trading markets are absent. Finally, the experience with GHG regulation in the EU's electricity sector may not be fully transferable to other systems because there is a broader range of competition in the EU's wholesale and retail electricity markets, and electricity rates at retail in the EU are often not cost-based rates.

A simple observation is nonetheless warranted. **The characteristics of CHP present unique opportunities and challenges in a multi-sector emissions trading system, and carefully tailored regulations to address CHP must be a high priority if California intends to capture the 9 million metric tonnes[1] of annual emissions reduction potential presented by CHP.**

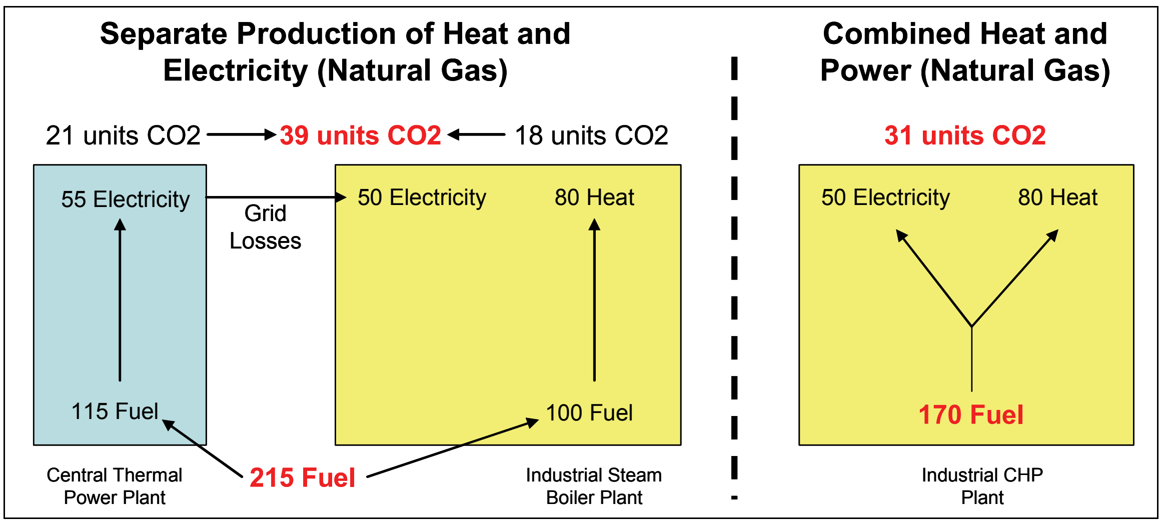
[1] Based on projection of CHP potential of 7.3 GW in California.

CHP and Emissions Trading

The system that has so far progressed furthest in the development of a GHG regime is the EU-ETS. Phase I of the ETS is due to conclude at the end of this year, with Phase II starting immediately on 1 January 2008. It is increasingly seen as a feasible framework on which a future global system can be based. The ETS development illustrates the challenge of effective integration of CHP into an emissions trading system.

When an industrial site invests in a high efficiency CHP plant, total emissions from the production of electrical and thermal energy are decreased. CHP increases the overall efficiency of energy production, and emissions attributable to CHP are more than offset by emissions displaced from separate central power generation and industrial boiler installations. Emissions at the industrial site, however, are increased. Figure A illustrates these emissions impacts.

FIGURE A
ENERGY FLOWS FOR SEPARATE AND COMBINED HEAT AND POWER GENERATION



In Figure A, an industrial facility producing heat from a steam boiler emits 18 units of CO_2, and the facility's purchase of electricity from the utility attributes 21 units of indirect CO_2 emissions to the industrial use of electricity. The combined emissions attributable to the industrial use of energy by this site is 39 units of CO_2. When the industrial facility installs CHP, the direct on-site emissions increase from 18 to 31 units of CO_2, but the total emissions attributable to the industrial facility's energy use are reduced from 39 to 31 units of CO_2. In other words, **while on-site emissions attributable to the CHP producer increase by 70%, net / global emissions reduce by 21%.**

The ETS framework adopted by the EU failed to reflect this key benefit of CHP. Because the ETS regulates emissions at the source, it imputes to the industrial site greater emissions without recognizing the reduction in indirect emissions in the electricity sector. Without CHP-specific measures, the installation of CHP would increase an industrial site's regulatory burden, resulting in a disincentive to development.

To overcome the CHP-related design flaw in the original ETS framework, several EU Member States have subsequently introduced allowance / permit allocation measures designed to encourage new CHP (and not penalize existing CHP) in ways that ensures that the ETS fairly reflects the considerable potential of CHP to reduce emissions. The main means used so far are as follows:

- **Benchmarking**. This is a means of allocating permits - not according to actual emissions but on the basis of comparison with the emissions of a typical, and often 'best available technology' (BAT), plant for a given energy output. In the case of allocation arrangements for CHP designed to reflect its efficiency advantage over separate generation, this means that allowance allocation for the electrical output is based on the emissions of a conventional fossil-fired power plant (most typically CCGT plants that do not recover heat) while the heat output can be based on the emissions of a conventional boiler or steam plant.

  Such 'double benchmarking', which can apply in trading systems based on auction or (as in the case of the ETS) free allocation, requires the use of fair reference values that reflect the emissions associated with separate heat and power (avoided emissions rather than the power system average) generation that are multiplied by the CHP energy outputs in order to determine the allocation to the installation. In the EU ETS, several countries have used benchmarking for CHP, including Germany and the Netherlands.

  The cornerstones of the benchmarking arrangements in the Netherlands are the electricity and heat reference efficiencies: for electricity (gas-fired) the benchmark is 50%; for heat, it is 90%[i]. This approach therefore reflects the efficiency benefits of CHP highlighted in the schematic provided earlier.

- **Reducing the Compliance Factor**. The compliance factor, which designates the percentage by which an emitter is required to reduce its emissions, is the principal means of ensuring downward pressure on emissions. If set at 1, there would be no requirement to reduce emissions below the baseline level; if set at less than 1, there is a requirement to reduce emissions. By setting the compliance factor for CHP closer to 1 than for non-CHP plants, more allowances can be allocated to it. For example, the Netherlands is currently using a compliance factor of 0.995 for CHP plants in the energy sector (requiring a 0.5% reduction) and one of 0.915 for non-CHP plants (requiring an 8.5% reduction).

- **A CHP Bonus**. This simple mechanism enables an additional level of allocation to CHP plants per unit of electrical output when compared with other electrical generating units. For example, in Germany, CHP plants can currently benefit from an additional allowance of 27t of CO_2 / GWh of electricity production. This represents a bonus of approximately 6% for a gas-fired 40 MWe CHP emitting around 470t CO_2 / GWh.

- **Creation of a Specific CHP Sector**. A starting point for EU Member States as they design their National Allocation Plans (NAPs) has been to break down the covered installations by sector in order that they can assign specific allocation arrangements to specific sectors. This leaves open an opportunity to place CHP plants in a specific CHP sector that can be treated in a way that reflects CHP carbon benefits, for example by setting a higher compliance factor or applying a CHP bonus. The UK, among others, will establish a CHP sector for the second phase of the ETS beginning in 2008.

The various NAPs under the EU ETS provide a range of allocation arrangements for both new and existing CHP plants, and a range of methodologies for calculating baseline emissions - these are summarized in the report. For the latter, CHP plants are treated similarly with other plants; with the former, there are differences.

For example, the Netherlands has used double benchmarking for both new and existing plants, while Germany has used a grandfathering approach that recognizes the benefits of CHP through use of a bonus allocation for existing plants and double benchmarking for new plants. Other countries have used the compliance factor incentive for one or another. In short, there is no readily identifiable trend.

The Impact of the EU ETS on CHP Development. Phase I of the EU scheme started in 2005 and we believe that it is too early to be certain of any significant impacts of these allocation methodologies on CHP market development. We would expect this to become clearer after a period of three years or so. In the meantime, the following observations are relevant:

- A new ETS phase begins, with different NAP arrangements, in 2008. We believe it likely that some potential CHP investors may have delayed making commitments until there is a clearer view of NAP arrangements for Phase 2, lasting for five years from 2008 to 2012.
- Existing plants in the EU have generally not been adversely affected by the allocation arrangements of Phase I. Some, although a minority, have even done well, reflecting 'early action' and the genuine emissions reduction such plants are already achieving.

The **US Regional Greenhouse Gas Initiative** (RGGI) is not as advanced in its development as the EU ETS, and has a projected start year of 2009. The experience to date shows, however, that, as with the ETS framework at the EU Commission level, the efficiency benefits of CHP have been largely ignored. CHP is addressed by the current RGGI framework (the Model Rule) but only the electric output, not the thermal output. It thus remains the responsibility of each member state to develop state implementation plans that capture the potential for improved energy efficiency that CHP can provide. To date, the best hope for CHP under the RGGI program is that states will either fund CHP directly or indirectly using set-asides or proceeds from allowance auctions, or states will explicitly include CHP as an offset measure. Maine is the only RGGI state so far considering a formal proposal to support CHP. As part of the state's adoption of the Model Rule, legislation in Maine includes a set-aside of emission allowances for industrial CHP facilities, though only for electricity consumed on-site. It is conceivable that this precedent will be accepted by other RGGI states.

The **US Clean Air Interstate Rule** (CAIR) is a federal requirement to reduce the interstate transport of pollutants. The program is directed at reducing nitrogen oxides (NOx) and sulfur dioxide (SO2) emissions from large (>25 MW) electric generating units (EGU) in 28 Eastern and Midwestern states and the District of Columbia through the use of a cap and trade emissions program. While not a GHG reduction program, CAIR further illuminates the need for regulations tailored to address CHP characteristics. Unlike RGGI, CAIR does include some specific measures for CHP in the form of a thermal credit for new CHP facilities that commenced operations after 1 January 2001. However, as this report elaborates, the recognition of CHP efficiency is incomplete.

Other Policy Strategies to Incentivise CHP

The report contains several examples of policy regimes and measures that have been in place long enough for clear and beneficial impacts on CHP market development to have taken place.

These include:

1. Policy Support:
    a. Perhaps the most important issue we have observed is that the government authority or ministry responsible for CHP must also have responsibility for energy market regulation and should have the commitment to intervene in markets in order to revise adverse regulatory issues and so deliver its CHP commitments.
    b. An important condition (though not in itself sufficient) is the setting of a CHP growth target that is based on a detailed understanding of the CHP potential. The majority of those jurisdictions that have seen the sharpest market growth have introduced such a target.

2. Fiscal Support. Policies that deliver a sufficient financial benefit to CHP projects nearly always work. They will work most effectively if the incentive is tied to the energy efficiency or environmental performance of the project. Examples of policies that have worked include:
    a. Electricity price benefits through incentive tariff arrangements for electricity exported to the grid. The Portuguese example highlighted in this report is one of the best examples.
    b. Fuel price benefits (as used during the Dutch success period with CHP in the 1990s, when high efficiency CHP users were provided with discounted gas tariffs).
    c. An obligation with a certificate-based trading system, similar to the Belgian and Dutch systems described in this report, link the financial benefit directly to the environmental or efficiency performance of the project.
    d. Tax incentives, for which there are several examples both in the US and Europe (including the UK Enhanced Capital Allowance, whereby investment in certain energy efficiency systems, including CHP, secures tax benefits).
3. Removing Barriers. This is an implied pre-condition to market growth. For example, a strategy that tackles grid access and interconnection issues is better placed to be successful than one that overlooks these potential barriers. It is significant that the EU CHP Directive includes this as a central pillar and there is plenty of experience elsewhere in Europe and in the US (including California) that highlights this issue.

A high level of political / fiscal support should require that support is directed towards high efficiency CHP schemes that yield significant environmental / societal benefits. The creation of a definition of 'high efficiency' or 'high quality' CHP has been used to improve the targeting of incentive measures. The UK CHPQA and the definition of CHP in the EU CHP Directive are both pioneering and, we believe, fair mechanisms for ensuring that incentives for CHP can be directly linked to the performance of the CHP project.

I. Introduction

This report has been prepared by Delta Energy & Environment, in partnership with Energy Insights and Sentech, for the Energy Producers and Users Coalition (EPUC) and the Cogeneration Association of California (CAC).

The report is aimed to meet the principal needs of the two organizations, summarized as follows:

1. To provide a clear understanding of the international and US experience to date of combined heat and power under GHG and renewable energy policies and regulations.
2. To provide a basis for the development of policy positions, technical recommendations and strategies that will be effective in securing as full a recognition as possible of the benefits of industrial CHP (both existing plants and future projects) in the development of GHG regulations arising from California Assembly Bill 32 (AB 32).

The report is designed to highlight in particular GHG regulatory schemes that recognize that CHP is the most efficient way to convert fuel into electricity and heat. We therefore aim to focus on measures that:

- Encourage new investment in CHP.
- Do not penalize those that have already invested in CHP and are therefore already providing substantial GHG reductions.

II. The EU Emissions Trading Scheme

A. Introduction

1. Basic Principles

The EU Emissions Trading Scheme (ETS) is the first international trading system for CO_2 emissions in the world. It was introduced in January 2005 across 25 countries. While it remains a controversial measure with some teething problems, it has worked reasonably well up to now and experience so far suggests that a firm platform has been laid for significant development and extension in the future.

The explicit aim of the EU ETS is to help EU Member States achieve lower cost compliance with their climate change commitments under the Kyoto Protocol. Key features include:

- It is a source-based system covering over 10,000 energy-intensive installations across the EU. Adopting what is thought to be the most logical approach to emissions trading, the ETS allowances are allocated to, and owned by, sources of CO_2 emissions.
- Sources include combustion / power plants (with thermal input exceeding 20 MW), oil refineries, coke ovens, iron and steel plants, and factories making cement, glass, lime, brick, ceramics, pulp and paper.
- Total source coverage represents close to half of Europe's emissions of CO_2.
- Phase I of the ETS is a three year program that runs to the end of 2007. Phase 2, with a five year duration, starts on 1 January 2008 and runs until the end of 2012.
- 'Carbon credits' are included in the scheme only to the extent that companies may use such credits arising from projects taken forward under Joint Implementation and the Clean Development Mechanism of the Kyoto Protocol to contribute to their compliance obligations. There is no quantitative limit placed on the use of such credits.

The ETS is essentially a 'cap-and trade' system. In such systems, a limited number of 'allowances' or 'permits' to emit are allocated, for free or through auction, to individual sources of emissions, including power plants and industrial installations. Installations that emit more than they have allowances to cover are required to buy allowances to cover the difference. Installations that emit less than they have allowances to cover may sell surplus allowances to those that need to buy. In this way a trading market is established based on the fact that those installations that can reduce emissions most cheaply will do so and sell surplus allowances to installations with higher abatement costs. In theory, therefore, overall compliance costs are reduced.

The overall framework for the ETS was originally agreed by Member States as an EU Directive in October 2003. This Directive laid down the basic elements of the system, including what emissions sources would be covered, what would be traded (allowances representing one tonne of CO_2), the administrative arrangements and some basic principles of allocation (including, for example, that for Phase I, no less than 95% of allowances should be allocated for free; for Phase 2, no less than 90%).

2. National Allocation Plans

Critically, the precise details of how many allowances are issued and how they are allocated is subject to each individual Member State, which develops National Allocation Plans (NAPs) that must be approved by the EU administrative authority in Brussels, the European Commission. The Directive contains guidance to Member States to help them prepare their NAPs, in particular that allocation arrangements should fairly correspond to the emissions trajectories needed to meet Member State obligations.

For example, Member States decide, among other things:

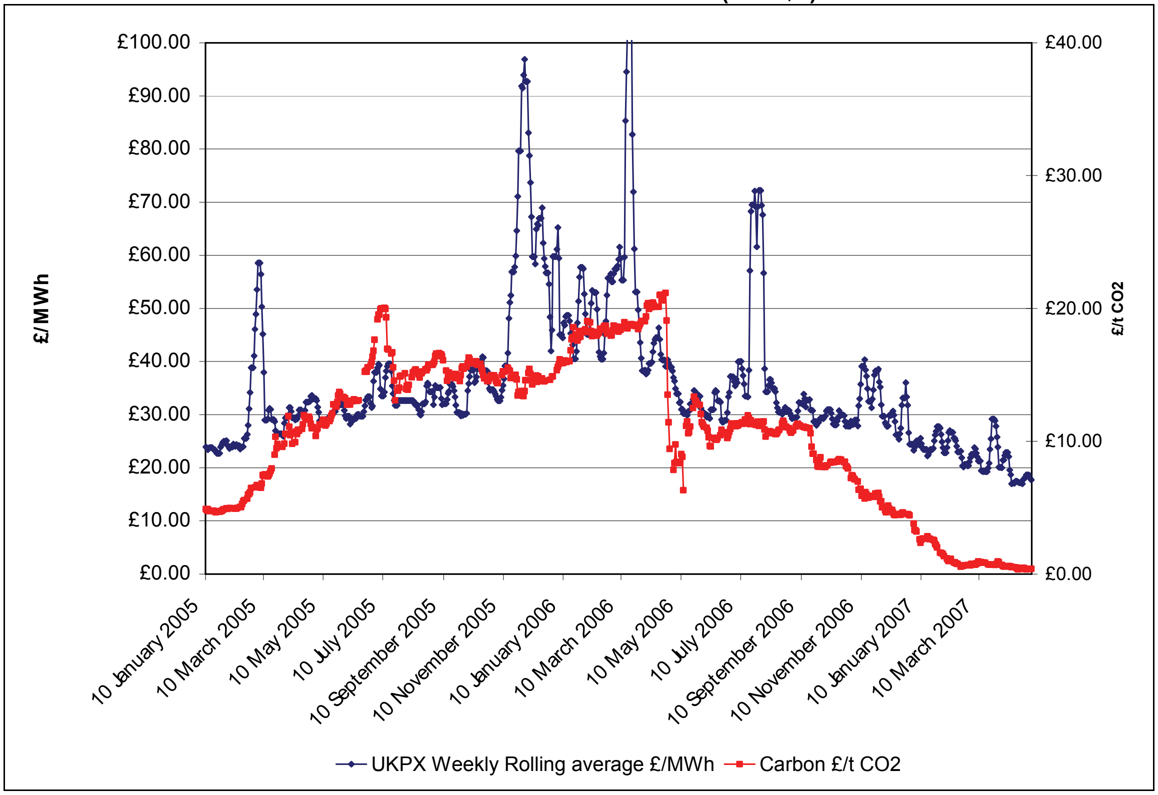
- The baseline period.
- Detailed rules for new entrants.
- Whether and how to apply grandfathering and / or benchmarking arrangements.
- Whether to allocate allowances on the basis that some sectors may have to take a greater reduction burden than others.
- Whether to include a CHP plant in the combustion / power plant sector, in the relevant industrial sector or in a special CHP sector (there is no opt-out available for CHP plants; all such plants with a thermal input exceeding 20 MW are included in the ETS).

3. An Assessment of the ETS So Far

While the ETS has operated broadly as intended, there have been some fundamental problems in implementation as a result of the different allocation approaches taken by Member States. In general, Member States have sought to provide as generous an allocation as possible and, as a consequence, there has been an over-allocation. The result of over-allocation has been an oversupply in the allowance market, resulting in very low allowance prices in recent months, and little environmental gain.

In particular, electric utilities have effectively benefited from a windfall of grandfathered allowances, even though the allocation structures for them have generally been more stringent than for industrial energy users. In addition, while the allowance price has varied greatly since 2005, it has had a strongly-correlated, upward impact on electricity prices (the EU electricity system is strongly market-based, thus increasing carbon costs tend to be reflected by increasing prices, although the relationship is complex), benefiting electricity producers and reducing the competitiveness of industrial energy users. Figure 1 shows recent trends in carbon and electricity prices in the UK.

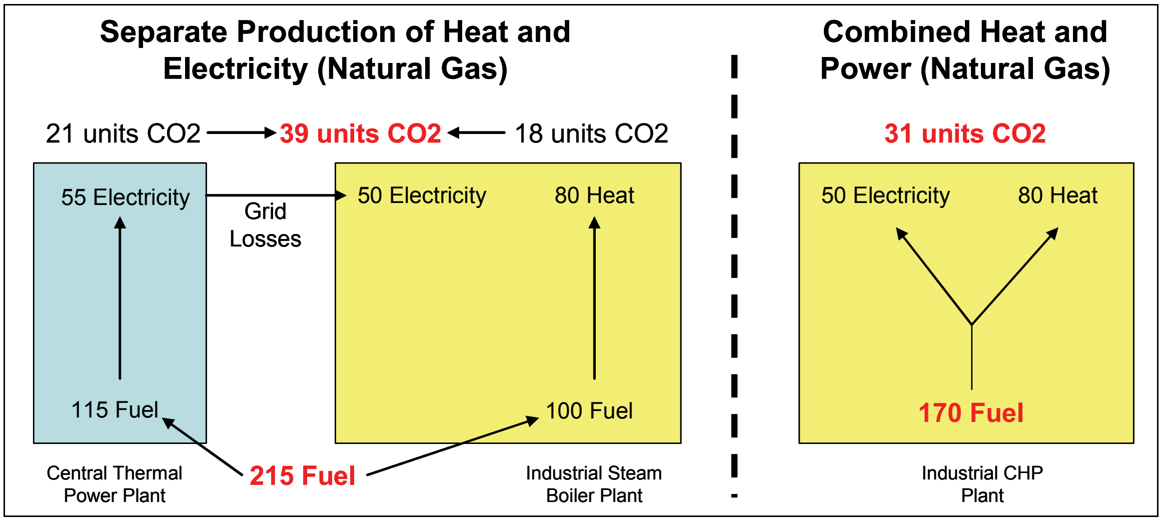
FIGURE 1
CARBON AND ELECTRICITY WHOLESALE PRICES IN THE UK (£1 = $2)



4. The Treatment of CHP

From the perspective of CHP, the overall design of the Directive is flawed in that it does not reflect the fact that CHP delivers an indirect rather than a direct reduction to emissions through displaced grid emissions. This is explained as follows: when an industrial site invests in a high efficiency CHP plant, total emissions from the production of electrical and thermal energy are decreased. CHP increases the overall efficiency of energy production, and emissions attributable to CHP are more than offset by emissions displaced from separate central power generation and industrial boiler installations. Emissions at the industrial site, however, are increased. Figure 2 illustrates these emissions impacts.

FIGURE 2
ENERGY FLOWS FOR SEPARATE AND COMBINED HEAT AND POWER GENERATION



In Figure 2, an industrial facility producing heat from a steam boiler emits 18 units of CO_2, and the facility's purchase of electricity from the utility attributes 21 units of indirect CO_2 emissions to the industrial use of electricity. The combined emissions attributable to the industrial use of energy by this site is 39 units of CO_2. When the industrial facility installs CHP, the direct on-site emissions increase from 18 to 31 units of CO_2, but the total emissions attributable to the industrial facility's energy use are reduced from 39 to 31 units of CO_2. In other words, **while on-site emissions attributable to the CHP producer increase by 70%, net / global emissions reduce by 21%.**

The ETS framework adopted by the EU failed to reflect this key CHP benefit. Because the ETS regulates emissions at the source, it imputes to the industrial site greater emissions without recognizing the reduction in indirect emissions in the electricity sector. Without CHP-specific measures, the installation of CHP would increase an industrial site's regulatory burden, resulting in a disincentive to development.

It has therefore been incumbent upon individual Member States to design NAPs in ways that can more effectively reflect the emissions reduction value of CHP. The treatment of CHP has varied greatly between countries, although not significantly between Phase I and Phase 2. Indeed, in some cases, the treatment of CHP is less reflective of its benefits in Phase 2 than Phase I. This section describes the principal CHP-related features of NAPs that Delta has selected on the basis that they present examples that have merit for consideration in the California context, while Annex I summarizes more generally a selected range of NAPs in respect of their treatment of CHP.

The following section highlights the main means that EU Member States have used to ensure that CHP is treated in ways that ensure recognition of the clear efficiency benefits.

B. Basic Principles of CHP Support in the EU NAPs

Four of the most common means of incentivising CHP are summarized below. They are not necessarily independent, and can be used together in various combinations.

1. Benchmarking

Benchmarking is a means of allocating permits not according to actual emissions but on the basis of the emissions of a typical, and often 'best available technology' (BAT), plant for a given energy output. Thus, installations with efficiencies greater than the benchmark receive enough (or excess) allowances to cover their emissions, while less efficient installations are short of allowances. Benchmarking therefore provides a clear incentive for efficiency.

In the case of allocation arrangements for CHP designed to reflect its efficiency advantage over separate generation, this means that allowance allocation for the electrical output is based on the emissions of a conventional power plant while the heat output is based on the emissions of a conventional boiler or steam plant. On the basis of the figures given in Figure 2 above, the CHP plant would be allocated allowances based on the emissions associated with 215 units of fuel used for the separate generation of steam and electricity. (In practice, this approach, also known as 'double benchmarking', has ignored the fact that CHP significantly reduces network losses.)

Benchmarking, which can apply in trading systems based on auction or (as in the case of the ETS) free allocation, requires the use of reference values, reflecting the emissions associated with separate heat and power generation, that are multiplied by the CHP energy outputs in order to determine the allocation to the installation. Reference values are determined by the EU Member States in their NAPs and in most cases, including the examples later in this section, correspond to CCGT power plant efficiency (around 50%) and boiler efficiency (80% or more).

In the EU ETS, several countries have used benchmarking for CHP, including Germany and the Netherlands. We believe that this approach represents a logical and balanced framework for allocation to high efficiency CHP under a source-based approach. 'Double Benchmarking' as used later in this section describes the systems adopted in the Netherlands and Germany.

2. Reducing the Compliance Factor

The compliance factor is the principal means of ensuring downward pressure on emissions. This factor, which is normally set at less than 1, is multiplied by the baseline emissions to give a reduced figure on which allocation is based.

Reducing or eliminating the compliance factor is the second-most used mechanism for using the NAPs as a promotional tool for CHP, for example when no distinct CHP sector has been created. This approach, with many country-specific variations, has been used in Austria, Belgium, France, Greece and Spain.

The Greek NAP I, which stated that "it is considered vital to promote and support cogeneration", has a compliance factor of 0.92 for non-CHP plants in some sectors, but a factor of 1 for CHP plants.

3. A Production-based Premium

The production-based premium enables a bonus or additional level of allocation to CHP plants per unit of electrical output. Member States that have adopted such an approach include the Czech Republic and Germany.

In the Czech Republic, CHP plants receive a bonus of 430 allowances for every GWh of electricity produced compared to non-CHP plants. Based on a price of €25 per allowance (not untypical for allowance prices in 2005 and 2006), this mechanism supports CHP-based electricity to a level of around €c 1.1 / kWh. In addition, 1.5% of the total number of allowances is earmarked for this bonus. Should the demand exceed the earmarked amount, the overall bonus is reduced across all beneficiaries.

4. Creation of a Specific CHP Sector

A starting point for Member States as they design their NAP is to break down the covered installations by sector in order that they can assign specific allocation arrangements to specific sectors. This leaves open an opportunity to place CHP plants in a specific CHP sector, where its benefits can be recognized, rather than in the industrial sector in which it happens to fall (e.g. paper or steel industries) where the CHP plants would be allocated allowances in the same way as all energy generation plants, whatever their type or efficiency.

For NAP 1, such a system was applied in Finland, Hungary and Poland. For NAP II, the UK has established a specific CHP sector based on a definition of CHP efficiency using the UK CHP Quality Assurance Programme (CHPQA). It is likely that related definitions will be used increasingly to target measures that reflect the efficiency benefits of CHP in the ETS, possibly within the context of a CHP Sector.

CHP efficiency and quality can vary greatly according to design and application. In reality, while well-designed CHP plants should achieve significant energy and environmental savings, some other plants may not. In order to better target the 'good' CHP plants, the use by policymakers of a definition for CHP is increasing as a means of ensuring that targeted measures and incentives apply only to those CHP plants that achieve a certain overall quality of performance or efficiency.

The principal definition at the EU level is one laid down in the 2004 EU Directive on CHP. The aim of this Directive (2004/8/EC) is to promote the use of high quality CHP in the European Union. A number of measures are recommended, including a standard method for defining high efficiency CHP on the basis of the primary energy savings (PES) made by CHP installations when compared to conventional separate electricity and heat generating plants. The definitions laid down by the Directive will be used increasingly across the EU.

C. Double Benchmarking

This section summarizes the Dutch and German approaches to double benchmarking in their NAP I and II and Italy's approach to this in NAP II.

1. The Netherlands – NAP I

The Dutch NAP I classifies its support mechanism for incumbent CHP as 'reward of early action'. The Dutch have a tradition of Energy Efficiency Benchmarking 'Covenants', whereby industry has been incentivised to adopt world best practice technologies, including high efficiency CHP. This approach forms the basis of the treatment of CHP in the NAP, which includes the following:

> 'In all cases, the following applies: if an installation has performed better than was required under the agreement, the installation is rewarded pro rata with extra allowances. If an installation has under-performed compared with its voluntary agreement, the installation receives pro rata fewer allowances.'

This approach has ensured that most Dutch CHP installations, signatories to the covenants, have been issued more allowances than needed to cover their emissions. Installations that do not reach world class level receive fewer allowances than they need to cover their emissions; for example, non-signatories are penalized by receiving only 85% of the allowances needed.

For both existing and new plants, the formula used for allocation is as follows:

A = EC x GS x CS x C

Where:

A Allocation to the installation.

EC Average annual emissions in the two year period 2001/02, calculated on the basis of the actual power and heat production 2001/02, and of reference efficiencies for power and heat (see below).

GS Growth factor resulting from expected sector production growth 2001/02 – 2006 (varies by sector).

CS Compliance factor for new entrants.

C General compliance factor for all installations included in the scheme (0.97).

For the energy sector, the growth and compliance factors are as follows; a higher compliance factor recognizes the benefits of CHP plants:

- For the power sector GS = 1.07 and CS = 0.915
- For CHP GS = 1.07 and CS = 0.995

In the industrial sectors, sector specific factors are used that incentivise CHP.

EC, the average annual emissions during the baseline period are calculated using the following formula:

EC = [ef(P) x Q(P)] / Eff(P) + [ef(H) x Q(H)] / Eff(H)

Where:

ef Emissions factor

Q Average annual production in 2001/02

Eff Reference efficiencies. Efficiency benchmark values are fuel specific; for natural gas an electrical efficiency of 50% and heat efficiency of 90% are used. For coal, an electrical efficiency of 39% and heat efficiency of 90% are used.

P Power production

H Heat production

Some regard the Dutch NAP I as the most balanced and fair NAP for CHP of all because of the double benchmarking approach. The 'over-allocation' of allowances to CHP projects that has resulted (on the basis that the plants are receiving more allowances than are needed to cover their emissions) has been limited to 15% of overall emissions, but can be less depending on the industry sector.

2. The Netherlands - NAP II

The Dutch NAP II is broadly similar to the NAP I. Again, the same principle of allocation applies to both new and existing plants. It is based on the following formula:

A = HE x GF x C x EE

Where:

A Allocation.

HE Historical emissions of this plant. To assess the baseline, choose the average of the three 'best' years out of a series from 2001 up to and including 2005.

GF A growth factor for the period 2006 – 2010. This is set at 1.07.

C A generic compliance factor to bring the sum of all individual allocations under the overall preset cap. This is applied to all allocations except for 50% of the allocation to process emissions.

EE The relative energy efficiency of the plant.

For the last factor, EE, a distinction is made between:

- Emissions from energy conversion installations, including power plants, CHP installations and steam boilers, etc.
- Emissions from combustion processes.
- Process emissions.

The energy efficiency factor is applied to emissions from combustion processes and from energy conversion plants, but not process emissions. For energy conversion installations, fixed benchmark efficiencies will be used for electricity and heat production. For all fuels, the heat efficiency benchmark is 90%. For electricity:

- For gas or oil fired plant - 52%
- For coal – 39%

Over-allocation is limited to 10% of the average historical emissions.

Existing plants receive an allocation based on historical emissions. Each new installation receives an allocation based on the expected annual energy production of the installation at the time of commissioning and reported to the authorities. This is based on electricity and heat capacities and the expected annual operating capacity factor.

3. Germany - NAP I

For new plants entering into operation after 1 January 2005, a double benchmarking methodology is used. The allocation of allowances is based on a comparison with BAT for the separate generation of power and steam. Depending on the fuel and the technology, the specific emission factor for the benchmark of power ranges from 365 (for natural gas based CCGT) to 750 tCO_2 per GWh. For steam, the emission factor ranges from 225 (for natural gas) to 345 tCO_2 per GWh. For warm water, the emission factor ranges from 215 tCO_2 per GWh for natural gas. (Note: if a CHP installation is on or near the natural gas network then the natural gas benchmarks are used regardless of the fuel used by the CHP installation.)

For a 350 MWe CHP plant, this benchmarking could result in an allocation of almost 30% more allowances than required.

For existing installations, simple grandfathering is the basis of allocation. For those plants in operation before 31 December 2002, there are two types:

- Those where less than 10% of emissions can be directly attributed to an onsite industrial process such as ammonia or cement production (formula 1 below).
- Those where more than 10% of emissions are attributed to a process (formula 2 below).

1. EA = EBP x EFP x tP + EASZ

2. EA = (EBP.ges – EBP.proz) x ((EFP x tP) + (EPB.proz x tP)) + EASZ

Where:

EA	Allocation for the period 2005-2007.
EBP	Average yearly emissions during base period (2000 – 2002).
EFP	Compliance factor.
tP	Number of years in period.
EASZ	The amount of special allocations of emissions allowances in the compliance period (2005-2007 or 2008 – 2012). For CHP plants, this includes a bonus 'compensation factor' for CHP plants amounting to 27t of CO_2 / GWh of electricity production.
EBP.ges	Annual average emissions during base period.
EBP.proz	Average process related emissions during base period.

For new plants or capacity extensions that came into operation between 1 January 2003 and 31 December 2004, allocation is based on reported emissions before the compliance period, with an ex-post correction allowable based on actual utilization of the unit.

4. Germany - NAP II

For new installations, double benchmarking has again been used, based on similar benchmarks to NAP I. The general allocation formula is:

Allocation = Plant capacity x Benchmark x standard capacity factor.

The standard CHP capacity factors, in hours per year, for the various industrial sectors are as follows:

- Paper 8,000
- Refineries 8,000
- Chemicals 8,000
- Food industry 7,000
- Hospitals 7,000
- District heat 6,000

For existing CHP installations, there is again an incentive arrangement based on a grandfathering approach. Given that the overall intention is to ensure that the power sector is responsible for the lion's share of the needed reductions, the compliance factor (the factor used to determine the degree to which baseline emissions must be reduced; the nearer the factor is to 1, the less the reduction required) is significantly higher for CHP plants (0.9875) than for power plants (0.85).

5. Italy - NAP II

In Italy the NAP I did not use double benchmarking and, at least for CHP, the first NAP was heavily criticized. The Italian NAP II uses a combination of double benchmarking and favourable compliance factor treatment to incentivise CHP.

For existing plants:

- The baseline year is set at 2005.
- Allocation is reduced year-on-year by a compliance coefficient which for both CHP and non-CHP plants is the same until 2008, but thereafter it remains at 1 for CHP and reduced to 0.74 for non-CHP CCGT plants by 2012.
- The electricity benchmark is fixed at 358 tCO_2 per GWh for both CHP and non-CHP natural gas plants.
- For CHP plants, the heat benchmark is set at 350 tCO_2 per GWh.

Note that the heat benchmark is particularly generous and to compensate for this, the overall allocation is multiplied by 0.85 (1 – assumed primary energy savings of 15%).

For new entrant plants, allocation is also based on this double benchmarking approach.

D. Plants Developed After Baseline Year

In general, the various NAPs of the EU ETS treat fairly those plants, including CHP plants, that are developed between the baseline year(s) and the start of the trading regime. In general, they are regarded as new entrant projects. We are not aware of CHP developers in any country that believe they have been adversely affected by allocation arrangements. Three examples include:

- Denmark:
  - Installations established prior to the publication of the NAP for the period 2005-07, on 31 March 2004, invested without knowing of the allocation arrangements. These installations have therefore been allowed a higher level of emissions than installations established after the allowance system.
  - Installations established in the period after 31 March 2004 knew about the allowance scheme at the time of their investment. Since this category includes new installations which are assumed to be more efficient than those established before 31 March, they received allowances in the first period (2005 – 2007) on a stricter basis.
- Germany – as with several other countries, allocation is made based on the projected output with a facility for later correction.
- The Netherlands – treats such plants as if they are new entrants.

It has certainly been the case that some CHP projects have been established in the interval between the baseline and trading periods without knowing the final details of the NAP. However, we understand that there have been cases where project developers have received some level of advance assurance from NAP regulators in order to minimize this uncertainty. It is also the case that all developers face some level of policy / regulatory uncertainty at all times and that the case of NAP development is just one more example.

E. The UK ETS

The UK Government claims that its Emissions Trading Scheme was the first economy-wide system to be used to reduce carbon emissions. It started in 2002 and finished at the end of 2006 in light of the emergence of the EU ETS. It was effectively a trial, was not obligatory, included only 33 direct participants and provided no specific benefits for CHP. The Scheme had four main phases:

1. Entry into the Scheme by one of four routes:
    - With a voluntary emissions target taken on through the 'financial incentive' (see below).
    - Through an existing target set through a voluntary 'Climate Change Agreement'.
    - Via an approved emission reduction project (the 'project credit route': a project is a defined activity which leads to reductions in emissions. Such a project can earn credits which could then be traded in the ETS).
    - By opening a trading account.
2. Allocation of allowances. Target Holders were allocated allowances either at the start or end of each compliance period – depending on the nature of their target. Those responsible for carrying out emission reduction projects were allocated project 'credits' which were traded in the Scheme and used to meet all targets.
3. Trading allowances. All Participants in the Scheme were able to trade allowances at any time. The only requirement was that they held an account in the registry.
4. Reporting and compliance. Target Holders were required to report their performance at the end of each compliance period.

There were two ways in which an emitter of greenhouse gases could take on a target in the Scheme:

1. Through a financial incentive made available by the Government (Direct Participants). Direct Participants were able to volunteer to take on an absolute target in return for this financial incentive. It was worth a maximum of £30 million per annum after tax, and was made available for five years. An auction was used to allocate both the absolute targets (on which the allocation of allowances was based) and the financial incentive.
2. Through a voluntary Climate Change Agreement (Agreement Participants). The Agreements contained targets set in either absolute or relative terms. Target units covered by an Agreement qualified for an 80% discount from the Climate Change Levy, a tax on energy supply designed to reflect, to a limited degree, carbon costs in electricity and fuel prices.

Non-Target Holders were able to participate in the Scheme in the following two ways:

- Emitters that did not wish to take on a target could enter through the project credit route.
- Any others not entering through the routes outlined above could register with the Emissions Trading Authority (ETA) and trade allowances / credits in the Scheme, irrespective of whether they were an emitter or not.

Assessment

The Scheme was source-based rather than load-based. In addition, and this is a critical distinction between the UK and EU systems, the electricity sector was not included in the Scheme and industrial power / heat associated emissions could only be included where they were used onsite. Industrial indirect emissions (for example those associated with electricity supply to the site) were included in allocation arrangements.

Given that there was no participation from the electricity sector and that entry into the Scheme was voluntary, and because there were no obvious mechanism to incentivise CHP, the UK Government has not been able to identify any new investments in CHP arising from the UK ETS.

The experience of the UK ETS has had little impact on the design of the EU ETS, which is significantly different in structure. The background to this is as follows: at the end of the 1990s, at the same time as the European Commission was developing its proposals for an EU scheme, the UK government devised and launched its own scheme within a very short time-frame. Many proponents of this scheme had the explicit intent to influence the design of the EU system so that it would be based on that of the UK.

In reality, the European Commission largely ignored developments in the UK and developed proposals for its own scheme largely independently. As the EU proposals moved forward and became Community law, the UK Scheme was largely ignored.

Because of the differences between the two systems, the UK ETS has also had little impact on the nature of the UK NAPs for Phase I and 2 of the EU ETS since the framework for allocation is laid down by the EU ETS Directive.

The UK Government , however, does appear to have recognized that its treatment of CHP in NAP I was inadequate. As a consequence, it has proposed for NAP 2 a specific CHP sector and an allocation arrangement for CHP plants with a compliance factor of 1 (see Annex I).

III. The Regional Greenhouse Gas Initiative (RGGI)

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Northeastern and Mid-Atlantic states to reduce carbon dioxide emissions. The RGGI Model Rule fails entirely to recognize the CO_2 reduction benefits available from CHP installations. Thus far, none of the RGGI member states has stepped forward to implement the Model Rule in a way to take advantage of CHP's benefits, but implementation efforts are still in the early stages and are evolving.

This section reviews

- A detailed review of the RGGI Model Rule.
- State progress and early actions on implementing the Model Rule. (Annex B provides more details on state implementation efforts.)
- The impact the RGGI Model Rule and state implementation will have on the CHP market-place.
- A summary of the above and possible means for mitigating adverse impacts on CHP.

A. RGGI Model Rule Overview

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Northeastern and Mid-Atlantic states to reduce carbon dioxide emissions. The August 15, 2006 (revised version released January 5, 2007) Regional RGGI Model Rule defines the general guidelines for how RGGI will operate when it goes into effect on January 1, 2009.[ii] It sets the technical parameters for a cap-and-trade arrangement while also offering flexible guidelines for participating states to base jurisdictional rulemaking. The subsections that follow collectively summarize the basic makeup of the Model Rule. Issues covered include:

- Regulated and exempted sources.
- Allowance budget cap and structure.
- Allowance allocation methodology.
- Tracking systems.
- Early reduction allowance qualification and timeline.
- Offset definition and use.
- Safety valve.
- Set aside requirement.
- Imports and associated emissions leakage.
- Economic impact.

1. Regulated and Exempted Sources

Under the Model Rule, any fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system that services an electricity generator with a nameplate capacity equal to or greater than 25 MW is subject to the "resource-based" RGGI CO_2 budget trading (cap-and-trade) program.

Per certain limited conditions, however, units supplying less than 10% of their annual gross generation to the electric grid may optionally be exempted by individual states. No opt-in provision exists in the Model Rule for sources that generate less than 25 MW. There is no apparent distinction made between pre-existing plants and new plants in the RGGI Model Rule, and given the apparent move to adopt auctions of allowances, all plants will need to purchase credits to emit CO_2. Though per below, states will have the option to create an allowance set-aside for new plants as a part of their program.

2. Allowance Budget (Cap)

Beginning on 1 January 2009, emissions of CO_2 from power plants in each participating RGGI state will be capped (see Table 1), with the caps (total and per state) remaining unchanged until 2015. The states will then begin incrementally reducing emissions by 2.5% annually over a four-year period to achieve a 10% reduction below the initial base annual CO_2 emissions budget by 2019.

TABLE 1
STATE CARBON DIOXIDE CAPS UNDER RGGI, 2009-2015

State	Emission Cap (short tons)
Connecticut	10,695,036
Delaware	7,559,787
Maine	5,948,902
Maryland	TBD
Massachusetts	26,660,204
New Hampshire	8,620,460
New Jersey	22,892,730
New York	64,310,805
Rhode Island	2,653,239
Vermont	1,225,830
TOTAL REGIONAL BUDGET	150,566,993

Under the RGGI cap-and-trade arrangement, states will issue one allowance per (short) ton of CO_2 emissions. (Per the RGGI Model Rule, "For the purpose of determining compliance with the CO_2 budget emissions limitation, total tons for a control period shall be calculated as the sum of all recorded hourly emissions (or the tonnage equivalent of the recorded hourly emissions rates).") The baseline period is 2003-2005. Each individual regulated power plant may buy or sell allowances, but must have a sufficient number of allowances to cover its CO_2 emission limit. The penalty for failing to have sufficient emission allowances at the end of the compliance period will be a deduction of three times the excess emissions from the regulated power plant's future allocation of allowances.

3. Allowance Allocation

Each participating state must decide how to apportion allowances, though the Model Rule explicitly stipulates that allowances must be distributed in the following categories accordingly:

- 25% minimum to public benefit
- 0%-75% allocation to RGGI sources
- 0%-5% optional new source set aside

Each state is required to sell (i.e. auction) at least 25% of its allowances, and use the associated revenues for consumer benefit or strategic energy purpose (described below). Any entity — regulated power plant owner, individual, environmental group or investor within or outside of the RGGI area — can purchase these allowances.

The remaining 75% of each state's allowances can be allocated as deemed appropriate by the states. States may choose to "give away" the allowances to regulated power plants, retain them for new plants, or auction them and use the related revenues to further provide public benefit.

RGGI states are currently debating the merits of two principal methods for equitably allocating allowances: 1. Allowance giveaway or 2. 100% auction.

- **Allowance giveaway to regulated plants**. This method, employed by the European Emission Trading System (ETS), is believed to help ease the transition to a new regulatory regime with new pollution control liabilities. Competitive pressures and individual firm decisionmaking are the chief determinants for how plants choose to utilize their allowances. Accordingly, plant owners can opt to use all of their allowances to cover their existing emissions, or instead to reduce emissions through efficiency enhancement projects and then sell excess allowances. Though unsubstantiated, allowance giveaways may help keep RGGI state power plants competitive with non-RGGI power plants that sell and buy electricity to and from the RGGI region.

  In the past, regulators have used either the level of average historical emission rates ("grandfathering") as the basis for allocations or allocation emission rates implied by the best available technology ("benchmarking"). Another method, output-based allocations, awards allowances in proportion to current electricity generation, updated each year to reflect changes in generation at that facility. Grandfathering on the basis of historic emissions rates tends to reward the most polluting plants and discriminates against firms that have already taken action to reduce emissions. Benchmarking tends to favor the plants that have effectively reduced their ratio of CO_2 emissions per unit output. Output-based allocations tend to level the playing field and allow for new entrants to gain market share.

- **100% auction.** The auction method directs regulated power plants to buy allowances in an open market spanning the RGGI states. The price for an allowance will be set by supply and demand, influenced by what it costs to reduce emissions or purchase offsets. Modeling done as part of the RGGI process, using a wide variety of assumptions, estimated that CO_2 allowances are expected to sell for between $1/ton to above $10/ton, depending on modeling assumptions and energy prices. Allowance prices will be influenced by energy costs, technological innovation, electricity demand, and the availability of efficiency improvements in existing generators, among other factors.

4. Allowance Tracking Systems

The Model Rule establishes an allowance tracking system through which an assigned regulatory agency can record allocations, deductions, and transfers of CO_2 allowances under the cap-and-trade program. The tracking system may also be used to track CO_2 emission offset projects, CO_2 allowance prices, and emissions from affected sources.

CO_2 allowances are directed to be held in, deducted from, or transferred among CO_2 Allowance Tracking System accounts. One compliance account is to be established for each CO_2 budget source.

5. Early Reduction Allowances (ERAs)

Each state may award early reduction CO_2 allowances (ERAs) to CO_2 budget sources for taking actions during an early reduction period (20 December 2005 through 1 January 2009) that result in an improvement in efficiency and an absolute reduction in CO_2 emissions reductions. Total facility shutdowns are not, however, eligible for ERAs. Requests for ERAs must be submitted by 1 May 2009 to be considered.

ERAs will ultimately be allocated to a budget source's compliance account by 31 December 2009 and may be banked without any limitation. So far, no specific state action on ERA decisionmaking has occurred. Discretion is left up to the states on whether incremental CHP or improved-efficiency at existing CHP facilities will be eligible to generate ERAs, but no facility that receives state-aid or whose output is used as a credit toward another regulatory requirement (e.g. a renewable portfolio standard) is allowed to generate ERAs under RGGI's Model Rule.

6. Offsets

The RGGI Model Rule allows regulated power plants to utilize offsets — alternative GHG emission reduction projects — to initially account for up to 3.3% of their overall emissions — an amount equal to approximately one-half of a source's average compliance obligation under the program. This means that a significant portion of the reductions under the program must occur at the power plants through output reductions or efficiency upgrades.

Permitting offset allowances from other sectors to achieve compliance is intended to expand GHG reduction possibilities, in addition to providing more flexibility and lower costs. A power plant owner/operator will be allowed to select the lowest cost emission reductions and apply them to a portion of a plant's emissions requirement.

The types of allowable offsets specified by the Model Rule include:

- Landfill methane gas capture and combustion.
- Sulfur hexafluoride (SF6) gas capture and recycling at electricity transmission facilities.
- Sequestration through afforestation (transition of land from non-forested to forested state).
- End-use efficiency for natural gas, propane and heating oil.
- Methane capture from farming/agricultural operations.
- Methane emissions reduction from natural gas transmission and distribution.
    - Forest management and grassland re-vegetation projects (may be added later).

RGGI's Model Rule does not allow offsets to be created by developing or converting an existing plant to a CHP facility.

To be eligible for inclusion in RGGI, offsets are required to meet a strict five-point set of standards; the offsets must be "real, surplus, verifiable, permanent, and enforceable," as stated in the MOU. Offset projects can take place anywhere in the US as long as that state has entered into a memorandum of understanding with the RGGI states that ensures the credibility of the offsets.

7. Safety Valve

RGGI's MOU sets two "safety valves" to limit prices for emission allowances. If the average market price for allowances exceeds $7/ton of CO_2 for a period of 12 months on a rolling average, regulated power plants will be permitted to use offsets allowances to cover up to 5% of their emissions (instead of 3.3%). If the average market price for allowances exceeds $10/ton of CO_2, offset allowances can be used to cover up to 10% of plant emissions. In addition, regulated power plants would also be permitted to extend by up to one year their compliance with the emission levels set by the MOU. The safety valve prices are adjusted upward by the Consumer Price Index plus 2% per year, beginning in 2006.

If a Safety Valve Trigger Event occurs twice in two consecutive 12-month periods, then:

- Offset allowances may be awarded to projects located anywhere in North America or from international trading programs
- The percentage of offsets that a source may use to cover its emissions shall increase to 5% of its reported emissions for the first three years of the compliance period and 20% of its reported emissions for the period beginning with the fourth year of the compliance period and continuing through the end of the compliance period.

8. Allocation of the Consumer Benefit / Set Asides

The Model Rule requires that states apportion at least 25% of their allocations to the consumer benefit or strategic energy purpose. However, the definition of what these benefits include remains vague, allowing each state to determine their own definition. The Model Rule explicitly suggests the following activities for potential set aside:

- Promotion of energy efficiency measures
- Direct mitigation of electricity ratepayer impacts
- Promotion of renewable or non-carbon-emitting energy technologies
- Stimulation or reward of investment in the development of innovative carbon emissions abatement technologies with significant carbon reduction potential.

9. Imports and Associated Emissions Leakage

Emissions leakage is the concept that there could be a shift of electricity generation from capped sources subject to RGGI to higher-emitting sources not subject to RGGI. RGGI modeling forecasts that, in the absence of controls on leakage, imported power could expand greatly, negating 40% or more of emission reductions derived from RGGI, and undermine RGGI's goal to cut emissions by 10% below 1990 levels by 2020.

The MOU says that the states will "pursue technically sound measures to prevent leakage from undermining the integrity of the program." An interstate working group is actively considering options for addressing leakage and will issue a report on the issue in December 2007.

RGGI issued an initial report on leakage on 14 March 2007 (http://www.rggi.org/emisleak.htm).[iii] RGGI is concerned about leakage from both internal (generators not covered under the Model Rule's limitations) and external (given the fact that only some of the states in the PJM Interconnection are RGGI members) generators. Unlike California, RGGI is limited in how it can control leakage under such conditions and it foresees modest levels of leakage to occur despite limitations in modeling capabilities. But given what it describes as the current political momentum toward a national program on CO_2, RGGI views leakage as a near- to mid-term concern.

Still, RGGI is recommending that existing and planned generator tracking systems in the region be modified to monitor regional emissions leakage.

The March 2007 initial report also discusses CHP's potential role in policy responses to leakage, specifically as a means to reduce electricity demand and indirectly reduce emissions leakage. The RGGI paper also describes CHP promotion as a no-regrets policy, and calls for reductions in barriers to CHP applications and creation of market incentives for CHP. Among the barriers cited in the RGGI paper include:

- Potential resistance by public utilities to open their systems to outside generation.
- Expensive transmission feasibility studies.
- Potentially high exit fees.
- High rates for supplemental and standby power.

The RGGI paper also raises the specter of using an emissions portfolio standard, which is an output-based emission standard above which resources would not be allowed to emit. RGGI believes that such an approach could eliminate the issue of leakage as all generation (and demand-side) resources would have a CO_2 footprint that would be included in such an output-based standard. The paper recognizes, though, that a fixed standard could still allow overall emissions to increase if electricity demand increased, and the potential of simply buying credits from outside the RGGI region to meet compliance.

10. Load-based Versus Resource-based Cap-and-Trade Programs

Several load-based cap-and-trade policies were proposed to RGGI staff during the two-year run-up to creation of the Model Rule. Staff, however, found load-based cap-and-trade approaches problematic for legal reasons. One issue is the problem of "contract shuffling", which allows electricity sellers to assign clean power to sales to RGGI load serving entities, while increasing carbon-intensive power assigned to non-RGGI sales. Furthermore, given RGGI's limited coverage to generators equal or greater than 25 MW in capacity, it makes it easier to shuffle existing renewables to RGGI without changing the sector's overall emissions profile at all, defeating the purpose of the cap-and-trade effort in the first place.

Furthermore, under the RGGI approach, a load-based cap would only indirectly impact the real-time dispatch of generators in the region, since generators would face no direct compliance obligation and related cost adder due to the load-based cap. However, as load-servicing entities would have carbon-intensity compliance options, they would attempt to minimize exposure to spot market purchases if they ended up being carbon intensive.

RGGI's March 2007 paper examined how a load-based system, akin to California's proposed load-based system, could prevent leakage from being an issue. Although RGGI staff view a load-based cap as a viable leakage mitigation mechanism, it highlights the above challenges and others in employing such a system. For example, RGGI staff believe that establishing load-serving entity baselines of emissions to require a complex, detailed analysis of historic bilateral power purchases and spot market purchases, and an estimate of the emissions related to those purchases. This would require the use of both generator attribute tracking systems and ISO market settlement systems to evaluate the contract path of load-serving entity electricity purchases. As a result, it would present significant additional requirements beyond those that would be required to track regional emissions leakage through a generator attributed tracking system.

There were other reasons RGGI did not adopt a load-based approach, including the belief among RGGI stakeholders that a national trading regime will be created in the future and that it will be a resource-based approached, not a load-based system. Furthermore, the load-based approach was proposed late in the RGGI debate, and thus parties were invested in completing the resource-based regime rather than taking on an entirely new approach.

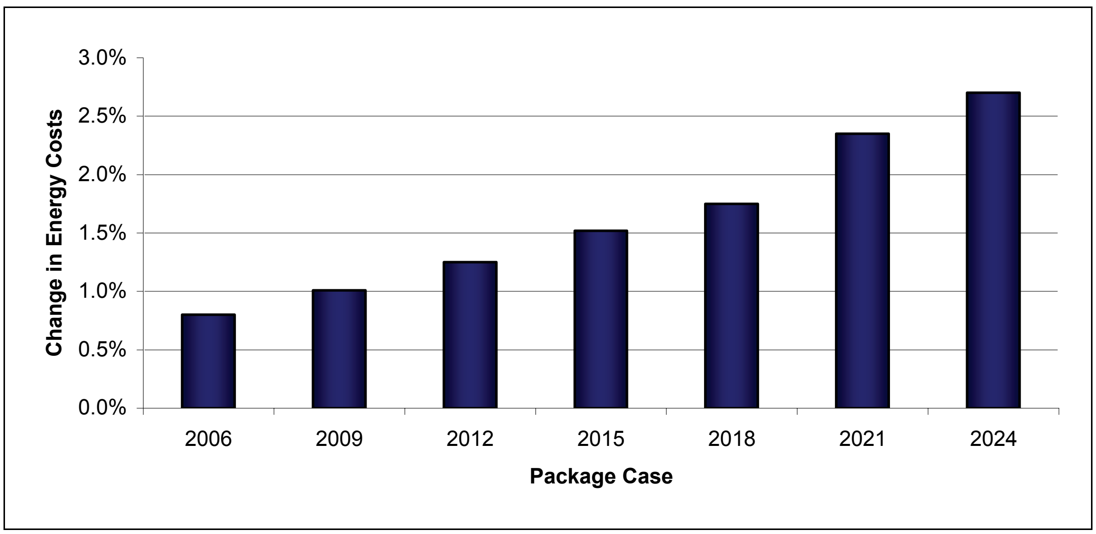
Bottom line is that RGGI staff recommends that:

> "If a load-based cap is considered, it should be implemented in parallel to the RGGI generator-focused cap-and trade system, and trading should not be considered between such systems, at least initially. Staff notes that the estimation of emissions attributable to electricity use is subject to significantly more uncertainty than the monitoring and reporting of emissions in a generator-based cap-and-trade system."[iv]

11. Economic Impacts

Figures based on August 2006 IPM modeling results (the modeling system used in the RGGI simulations, and also used by the US EPA) indicate that overall energy costs in the RGGI region are expected to increase by 0.8%-2.75%, with projected household bills estimated to increase by $3-$22 annually (see Figure 3). Furthermore, modeling indicates that household bill impacts by RGGI will be minimal. By 2015, RGGI compliance is estimated to raise residential electricity bills by $0.77-$36.84/year, and by 2021, by $2.16-$45.99. Increases in energy efficiency are, however, expected to mitigate cost increases or provide a net dollar benefit to energy consumers.

FIGURE 3
FORECASTED CHANGE IN ENERGY COSTS IN RGGI REGION STATES



B. Summary of States' Processes and Decisions on Adoption

Individual signatory states are now working to both adapt the RGGI Model Rule to state-specific formatting and develop state-specific policies to fill in blank sections of the Model Rule. Each signatory state must commit to establishing in statute and/or regulation its program and have its component of the regional program effective no later than 31 December 2008.

Rulemaking processes differ markedly between the participating states, with some placing greater emphasis on the statute level, subsequently allowing for more expedient rulemaking, and vice-versa. Thus far, only Connecticut, Maine, New York and Vermont have produced "pre-proposals" for public comment of their respective state model rules. The other states are in various stages of development. New Hampshire is likely to be the last of the participating states to complete its final rulemaking. Most states are aiming to have at least preliminary rules available by the end of 2007.

The RGGI Model Rule provides a fair amount of flexibility to help participating states address idiosyncratic challenges and provide for a degree of independent thinking. States can either adopt the RGGI Model Rule or make state-specific revisions that are consistent with the Model Rule. Key issues left open for state determination include:

- Size of the consumer benefit set-aside (25% or greater).
- Uses for the revenues derived from the consumer benefit set-aside (e.g., what types of projects will be supported and to what extent).
- Allowance allocation methodologies (giveaway versus auction).
    - Participating states appear to be favoring the auctioning of 100% of their allowances. Connecticut, Maine, New York and Vermont advocate for the 100% auction in their pre-proposals, while other states have verbally stated that they are "strongly considering" the 100% auction concept as well.

Summaries of each participating state's rulemaking status and specific RGGI implementation issues are included in Annex II.

C. Characterization of CHP-specific Issues

Despite the support for CHP found in the March 2007 RGGI report, the RGGI Model Rule still supports an input-based allowance arrangement that favors fuel switching and "back-end" solutions over the efficiency and emission reduction benefits inherent to combined heat and power units. The upshot: **the Model Rule creates a disincentive to use high efficiency CHP units, and instead promotes the separate generation of industrial process steam (that is not covered by the Model Rule) and electricity (that is covered by the Model Rule).**

By failing to exempt CHP units from RGGI, the Model Rule effectively penalizes industrial technologies that have a combined electric and thermal efficiency higher than electric-only generation plants. Meanwhile, the potential options for further reducing CHP CO_2 emissions are limited due to CHP's existing efficiencies, which are already much higher than traditional central station generation. Based on modeling done under the RGGI effort, CHP units account for about 2% of overall electricity generation in RGGI states, and only 4% of fossil-fuel fired generation; that percentage is projected to decline during the simulation period.

Counter-intuitively, the RGGI Model Rule envisions ERAs being generated via CHP, specifically, in gathering data to verify its use of thermal energy (via sold steam output), though nowhere in the draft rule is CHP specified as being eligible for ERAs:

> "CO_2 budget sources selling steam should use billing meters to determine net steam output. A CO_2 budget source whose steam output is not measured by billing meters or whose steam output is combined with output from a nonCO_2 budget unit prior to measurement by the billing meter shall propose to the REGULATORY AGENCY an alternative method for quantification of net steam output. If data for steam output is not available, the CO_2 budget source may report heat input providing useful steam output as a surrogate for steam output."

The irony is that CHP, if properly incentivized, could become a tool to reduce RGGI region CO_2 emissions and leakage. A 2005 analysis by Energy and Environmental Analysis (EEA) found that there is approximately 24,000 MW of technical potential for CHP in the RGGI region. Using the RGGI IPM model, if 10% of that potential was realized by 2020, 4.1% of then projected electricity use could be displaced from the electric grid.[v]

Reportedly, a large CHP plant fired by coal at Kodak's Rochester campus led to stakeholder conflicts on CHP policy during the RGGI Model Rule development. Certain stakeholders did not want coal to benefit from the RGGI Model Rule, even by granting CHP an exemption or a thermal credit, so a coalition for CHP did not come together in RGGI negotiations.

Some stakeholders argue that the Model Rule's regulatory focus on larger plants (those 25 MW and larger) excludes the majority of CHP units from regulation and thus, will not significantly impact some existing CHP units. According to the CHP database created by EEA for the Oak Ridge National Laboratory, the 10 RGGI states had (in May 2005) 14,048 MW of CHP at 745 sites, of which 12,659 MW at 100 sites have a capacity of 25 MW or larger, and thus covered under RGGI.[vi] (We have not been able to verify these estimates with RGGI stakeholders.)

But as with California, where roughly 90% of the state's CHP capacity comes from plants that are greater than 20 MW, the vast majority of RGGI state CHP capacity will be regulated under RGGI and potentially with significant downside impact. If states implement the Model Rule without taking into consideration CHP's utilized thermal output, then existing plants will be assessed a liability. Similarly, future construction of larger-scale units is likely to be restrained. In the face of such problems, some RGGI stakeholders believe that other, independent measures should be adopted by the states to support CHP, for example Connecticut's Tier III renewables designation for CHP and energy efficiency under the state's Renewable Portfolio Standard.

The RGGI Model Rule does, however, provide a measure of flexibility for individual states to implement unique provisions that could potentially aid in CHP's development. The principal means for states to improve CHP's standing are to:

- Make CHP a qualified offset resource (per the thermal output and sale data collection requirement in the Model Rule)
- Apply a percentage of allowance auction revenue to a CHP set-aside.
- Recognize thermal credit in an output allocation paradigm (i.e. a CHP bonus).

1. CHP offset qualification a potential long-term possibility

The prevailing thinking by RGGI stakeholders is that CHP will eventually become qualified as an offset in the long term. The challenge is that a regional program like RGGI must have comparability between states for offsets (e.g. for one state to allow for CHP offsets without recognition and agreement by the other states would create a different currency). States plan to focus initially on implementing the RGGI Model Rule's existing offset categories; but they will also acknowledge additional offset categories that are suggested during future public comment periods, and later work with the proposed RGGI oversight body to include other offset categories as they make sense.

According to Chris Young, Policy Specialist at Pace Law School, there were proposals during RGGI Model Rule negotiations to qualify CHP as an offset. A significant level of interest was generated by results from a couple of regional studies. For example, a Maine study identified CHP as one of the most cost-effective ways for the state to control its GHG emissions. But as the offset proviso was being negotiated, parties became concerned about opening up the number of offsets, and CHP was ultimately not deemed a qualified offset category. Looking forward, though, individual states can potentially include CHP as an offset category through the energy efficiency measure category.

2. Output-based allocation option

Individual states can opt to allocate allowances based on output by simply granting allowances to qualifying generators instead of auctioning them off. In this approach, a state could, for example, issue an output-based allocation to large cogeneration plants based on their thermal and electricity output characteristics. Such an approach would be the most beneficial to CHP if the full utilized thermal output was included in the calculations for allocations. Per Joel Bluestein, former president of Energy and Environmental Analysis (and a leading analyst in CHP and emissions regulatory policy):

> In order to properly credit the efficiency of a CHP system under an output-based allocation program, the program must recognize both the thermal and electric output of the CHP system. The efficiency of CHP results from the combined generation of both electricity and thermal energy. This efficiency cannot be reflected unless both are recognized. In a cap and trade program that includes both electric generators and large non-electric generating boilers, this can be done by allocating allowances to the CHP unit for its electric output from the electric generator pool of allowances and for its thermal output from the non-electric generator pool of allowances. In a cap and trade program that addresses only electric generators, the thermal output can be converted to MWh equivalent and added to the unit's output for the purpose of calculating allocations.[vii]

Indeed, an output-based allocation is an incentive for increased construction of new, more efficient CHP plants and the retirement of old, less efficient plants. This scenario is, however, considered unlikely, if most RGGI states implement 100% auction.

C. Summary of RGGI and Impacts on CHP

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by ten Northeastern and Mid-Atlantic States to reduce carbon dioxide emissions from electric generation plants with a capacity of 25 MW or larger. The 15 August 2006 Regional RGGI Model Rule (revised version from 5 January 2007) defines the general guidelines for how RGGI will operate when it goes into effect on 1 January 2009. It sets the broad technical parameters for a cap-and-trade arrangement while also offering very flexible guidelines for participating states to base jurisdictional rulemaking. Thus, even though the Model Rule is punitive toward CHP, state actions – many that are already under discussion – have the potential to lend support to existing and future CHP facilities.

The Model Rule supports an input-based allowance arrangement that favors fuel switching and "back-end" solutions over the efficiency and emission reduction benefits inherent to CHP units. The upshot: the Model Rule creates a disincentive to use high efficiency CHP units, and instead promotes the separate generation of industrial process steam (that is not covered by the Model Rule) and electricity (that is covered by the Model Rule).

By failing to exempt CHP units from RGGI, the Model Rule effectively penalizes industrial technologies that have a combined electric and thermal efficiency higher than electric-only generation plants. Reportedly, RGGI's stakeholders were considering a more favorable standing for CHP, but some parties were hesitant to support CHP given that some RGGI region CHP plants are fueled by coal. Thus, the electric-production facility of CHP is required to comply with RGGI requirements, with no credit given for the thermal energy produced.

1. State Implementation of RGGI as Option for CHP

Despite the pejorative approach RGGI has taken toward CHP, there are a few options whereby CHP might be able to improve its standing under the regime. Most of these will be achieved through state implementation of the Model Rule. That is because the RGGI Model Rule provides a fair amount of flexibility to help participating states address state-specific challenges and provides for a degree of independent thinking. States can either adopt the RGGI Model Rule or make state-specific revisions that are consistent with the Model Rule. The key issues left open for state determination that can be used by states to support CHP include:

- Size of the consumer benefit set-aside (25% or greater).
- Uses for the revenues derived from the consumer benefit set-aside (e.g., what types of projects will be supported and to what extent).
- Allowance allocation methodologies (distribution versus auction).
- Conceivably, states could adopt a double benchmarking approach for CHP or other allocation method that would not be pejorative toward CHP. Indeed, given that the Model Rule provides detailed direction on how the data for the thermal output of CHP is to be collected for ERA eligibility, the Model Rule effectively endorses acceptance of CHP as a noteworthy technology.
- CHP facilities that are awarded free allocation of CO_2 allowances, without having to pay for them, will not be unduly burdened by RGGI and, potentially, could undertake cost-effective improvements to their operations to produce credits they could sell to other RGGI-regulated generation facilities to further reduce CO_2 emissions. This is a proposal in Model Rule implementation in Maine.

To date (15 May 2007), though, four states (Connecticut, Maine, New York and Vermont) have issued draft implementation rules, but our discussions with policymakers in the six other states indicates that there are other prospective state activities that could (but will not necessarily) support CHP, including:

- Maine is proposing to create a set-aside of the state's annual emissions for CHP systems sited at industrial facilities. The set-aside would be limited to the amount of power consumed on-site, and not include power exported to the grid. All allowances would be auctioned.
- Connecticut's draft plan calls for an auction of emission allowances, which could provide funds for other measures such as energy efficiency investment, which might include CHP support.

- Massachusetts governor's call for an auction and for funding of (among other activities) CHP with the proceeds.
- New Jersey governor's plan to auction allowances in order to fund energy efficiency and renewable energy, though he did not specifically cite CHP as eligible for funding.
- The draft New York implementation rule that calls for auction of 100% of the allowances and resulting revenue to be used to fund energy efficiency, renewable or non-carbon-emitting technologies, and/or innovative carbon emissions abatement technologies; it remains uncertain whether CHP will be included.
- The draft Vermont rule that also calls for 100% auction, and there is a possibility that Vermont may provide a thermal credit for CHP.

Related, given that the Model Rule does allow offsets (which are certified emissions reductions or carbon sequestration that take place outside the electric generating sector in project areas that meet the program requirements) to make up for shortfalls in source reductions, there is a possibility that CHP might be able to positively contribute via this approach. But the only types of allowable offsets specified by the Model Rule include:

- Landfill methane gas capture and combustion
- Sulfur hexafluoride (SF6) gas capture and recycling at electricity transmission facilities
- Sequestration through afforestation (transition of land from non-forested to forested state)
- End-use efficiency for natural gas, propane and heating oil
- Methane capture from farming/agricultural operations
- Methane emissions reduction from natural gas transmission and distribution
- Forest management and grassland re-vegetation projects (may be added later)

CHP is not explicitly referenced, though CHP might be eligible under the "end-use efficiency for natural gas" category. There is a possibility that states might individually be able to include CHP as an offset measure under the efficiency category, though given that the RGGI's Model Rule specifically states that offsets cannot be created by developing or converting an existing plant to a CHP facility, this is an unlikely scenario.

2. Bottom Line for CHP within the RGGI Framework

The to-date RGGI experience illustrates the precarious position CHP has vis-à-vis GHG policy formulation. Despite the creation of a source-based cap-and-trade program for the electric power sector in the Northeast – a policy that should benefit CHP – policymakers have so far created more obstacles to CHP than incentives. CHP is covered by the RGGI Model Rule, but only the electric output, not the thermal output (which so far is being ignored). Meanwhile, the potential for improved energy efficiency that CHP has demonstrated is not explicitly being allowed as an offset under the Model Rule, though some stakeholders believe it will eventually be accepted by some states in state implementation plans.

There are some areas of positive policymaking in regards to CHP. The main one is that individual states (e.g. Massachusetts and Vermont) are apparently set on pursuing policies whereby the auction of emission allowances would funnel resources back to CHP as an energy efficiency and CO_2-reduction measure, and CHP's thermal output might be included into consideration of its impact.

IV. Treatment of CHP in NOx Regulation

A. Introduction

This report provides a summary of an existing US emissions cap and trade program, the Clean Air Interstate Rule (CAIR) and a high level summary of proposed federal legislation targeting greenhouse gas emissions. The US Environmental Protection Agency (EPA) CAIR model rules and state actions pertaining to allowance allocations are reviewed in the context of their treatment and effect on CHP.

Appropriate allocation of emission allowances is the critical factor in encouraging the development of a portfolio of clean and efficient technologies such as CHP. Primary lessons learned from the federal CAIR program that are relevant to CHP in the developing California AB 32 GHG program are:

- Improvements in the allocation of emissions allowances to existing generation facilities to prevent windfalls and;
- The need for improvements beyond the CAIR model rule that recognize the efficiency of CHP relative to the separate generation of the thermal energy and electricity it displaces.

It is worth noting that the potential for a federal GHG regulation has heightened with the Supreme Court's ruling of 2 April 2007. Any future federal GHG cap and trade program may likely follow the precedents set by the CAIR, NOx state implementation plan (SIP) Call and SO_2 Acid Rain trading programs. These programs are all source-based, affect primarily large electricity generators, and allow states some flexibility but set requirements in order to participate in interstate trading programs. However, the Supreme Court's ruling of 2 April 2007 (Massachusetts versus EPA et al), which gave authority to the EPA for GHG reductions and the resulting preemption may affect the flexibility granted to individual states.

B. Clean Air Interstate Rule (CAIR) Overview

On 12 May 2005 EPA published the final version of the Clean Air Interstate Rule (CAIR) in Federal Register, 70 FR 25162. CAIR is a requirement to reduce the interstate transport of pollutants that significantly contribute to non-attainment of ozone and fine particles (PM2.5) concentrations. The program is directed at reducing nitrogen oxides (NOx) and sulfur dioxide (SO_2) emissions from large (>25 MW) electric generating units (EGU) in 28 Eastern and Midwestern states and the District of Columbia through the use of a cap and trade approach.

CAIR has three separate markets – annual SO_2 emissions, annual NOx emissions and ozone-season NOx emissions. CAIR sets a two-phase declining cap for annual emissions of NOx and SO_2 in states that contribute to PM2.5 non-attainment; and a two-phase declining cap for ozone season NOx emissions for states that contribute to ozone non-attainment as follows:

- Phase I NOx cap for annual and ozone season[viii] emissions: 2009 - 2014
- Phase II NOx cap for annual and ozone season emissions: 2015 and thereafter
- Phase I SO_2 cap for annual emissions: 2010 - 2014
- Phase II SO_2 cap for annual emissions: 2015 and thereafter.

States are obliged to achieve their federal CAIR caps. However, states are not required to achieve their reductions exclusively from EGUs, nor are they obligated to adopt and implement the model rule. CAIR offers the states the option of joining one or all of these trading programs or meeting an individual state's emissions "budget" through measures of the state's choosing. States may achieve the reductions by imposing stack-specific emission standards on EGUs (rather than a cap-and-trade program) or by reducing emissions by an equivalent amount from other sources. However, if a state wants its EGUs to participate in the regional trading programs, it must adopt the model rule in its CAIR SIP. The main flexibility offered to states in the rules is in allocation of NOx allowances to affected units and "opt-in" provisions.

Issues covered in this report deal only with the NOx trading programs. As of 2009, EPA will no longer administer cap-and-trade programs adopted under the NOx SIP Call Rule (63 FR 61712, 10 October 1997). The CAIR NOx trading program supersedes the existing NOx Budget Trading Program. Separate NOx budgets have been assigned to states for the years 2009 and 2015 for both the annual NOx emissions market and the seasonal NOx emissions market. Table 3 highlights the primary aspects of each NOx market model rule and the flexibility of states in the development of the trading programs.

TABLE 3
CAIR NOX TRADING PROGRAMS

Annual NOx Emissions Market – Model Rule	Ozone Season NOx Emissions Market – Model Rule	Flexibility for States in Trading Program Development
Each state is assigned an annual NOx budget in tons for 2009 and 2015. Allowances are allocated by the states. NOx SIP call allowances and ozone-season NOx allowances cannot be used for compliance with the annual CAIR requirement. In addition each state will have a share of the compliance supplemental pool (CSP) that is comprised of 200,000 annual NOx allowances apportioned on a pro-rata basis proportional to the states share of total emissions requirements for the region in 2009. States may distribute the CSP allowances based upon criteria for early reduction and need. There are no restrictions on the use of the banked annual allowances or CSP allowances.	Each state is assigned a seasonal NOx budget in tons for 2009 and 2015. Ozone season NOx allowances are allocated by the states. Pre-2009 NOx SIP call allowances can be banked into the program and used by CAIR-affected sources for compliance with the ozone season NOx program. NOx SIP call allowances will not be issued after 2008. Banked NOx SIP call allowances cannot be used to meet the annual NOx emissions budget. There are no restrictions on the use of banked allowances.	For the most part, states must comply with the Model Rule language dictated by EPA to participate in the trading programs. The states do have flexibility in determining the following aspects of the plan: • Development of allocation methodology provided allocation information is submitted to EPA in required time. This includes cost of allowance distribution (free vs. auction), frequency of allocation (permanent vs. periodically updated), basis of distribution (heat-input vs. power output), and use of allowance set-asides and their size, if used (e.g., new sources, energy efficiency, development of IGCC, renewables or small units). • Provisions that allow individual units to opt-in the trading program so long as the units comply with monitoring requirements.

CAIR originally required that states file with EPA SIPs addressing federal CAIR requirements by September 2006. However, on 28 April 2006, EPA published in the Federal Register (71 FR 25328) a Federal Implementation Plan (FIP)[ix] that would implement the federal CAIR program if states do not submit SIPs. The FIP gives states the option of filing a full SIP by 11 September 2006 or filing an "abbreviated SIP" by 31 March 2007 that may include state-specific provisions but otherwise adopts the model rule. If a state does not file a CAIR SIP, EPA will administer the CAIR program in the state pursuant to the FIP and will allocate CAIR NOx ozone season allowances to state facilities pursuant to the model rule allocation methodology. In a Notice of Data Availability (NODA) published in the Federal Register on 4 August 2006 (71 FR 44283), EPA provided facility-specific allocations for 2009 through 2014 that would apply if a state does not file a SIP[x]. However, EPA will not record 2009 CAIR NOx ozone season allowances in facility accounts until October 2007, giving states time to submit and have their SIPs approved by EPA before EPA allocates allowances. In the case of an approved SIP, EPA will allocate 2009 CAIR NOx ozone season allowances pursuant to the state regulation, rather than the model rule.

1. Affected and Exempt Sources

Affected sources are EGUs >25 MW (nameplate capacity) that burn fossil-fuel and sell electricity unless EGU qualifies for the cogeneration unit exemption. Cogeneration units are defined as units having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through sequential use of energy and meeting certain operating and efficiency standards. **The model rule exempts cogeneration units from the cap and trade program if they meet PURPA efficiency standards and sell no more than one-third of their potential electrical output capacity to the grid, or sell no more than 219,000 megawatt hours (MWh), whichever is greater.**

CAIR allows states to decide whether to include a provision that allows non-CAIR units to "opt-in" to the CAIR program. However, states cannot require units to opt-in. To be eligible, units must vent through a stack and meet federal monitoring, recordkeeping, and reporting requirements (i.e., 40 CFR Part 75). The model rule allocates CAIR NOx Ozone Season allowances to opt-in sources at 70% of their baseline emissions using a heat input-based methodology and increases the state's CAIR budget proportionally.

2. Process for State Emissions Budgets

EPA determined state emissions budgets on a fuel-adjusted heat-input basis. State budgets were determined by multiplying historic heat input data (summed by fuel) by different adjustment factors for the different fuels. These factors reflect for each fuel (coal, natural gas and oil) the 1999-2002 average emissions by state summed for the CAIR region divided by the average heat input by fuel by state summed for the CAIR region. The resulting adjustment factors from this calculation are 1.0 for coal, 0.4 for natural gas, and 0.6 for oil. The factors were intended to reflect the inherently higher emissions rates for coal-fired plants and consequently the greater burden on coal plants to control emissions. These fuel adjustment factors initially favor older, more polluting plants and weight allowance allocation towards coal-fired units and states with more coal generation.

The CAIR model trading rule provides an additional pool of allowances available for allocation in the 2009 control period to those CAIR NOx units achieving early NOx reductions in 2007 and 2008 or whose compliance for the 2009 control period would create undue risk to electric reliability during the year 2009. This pool of NOx allowances, the compliance supplement pool (CSP), equates to an additional 200,000 tons for the annual NOx program. The rules outline the requirements for the request by CAIR NOx sources of allowances from the compliance supplement pool. EPA is apportioning the CSP allowances on a pro-rata basis, based on each state's share of the total emissions reductions requirement for the region in 2009.

3. Emissions Allowances

The EPA model rule allocation for the annual NOx program is described in subpart EE, § 96.142 of the Model Rule and allocation for the ozone season NOx program is described in subpart EEEE, § 96.342. The provisions are identical in construction and are summarized in Table 4. The model rule allocates allowances on the historic (baseline) heat input for each unit. Calculations of heat input for existing and new units are different. Once the baseline heat input is calculated for all affect units, each unit then receives the allowances proportional to its share of the total baseline heat input in the state. The allowances available for allocation are the portion of the state emission budget minus the new source set aside. The new source set aside is 5% of the budget in 2009-2014 and 3% in 2015 and thereafter.

TABLE 4
EMISSIONS ALLOWANCES IN CAIR NO_X MODEL RULE

	EPA CAIR Model Rule
Definition of existing unit	Commences operation prior to 2001.
Baseline period for existing units	2000-2004, fixed.
Existing-unit allocation metric	Average of three highest baseline years of heat input, with fuel factor adjustment (pre-2001 units).
Definition of new unit	Commences operation on or after January 1, 2001.
Baseline period for new units.	First five full years of operation, fixed.
New-unit allocation metric	Average of three highest five baseline years of "converted input" (2001 & newer units).
Allocation schedule and lead times	An initial allocation is made in 2006, for years 2009-2014. For allocation in 2009, and annually thereafter the allocations are reallocated every year for the six years later.
Percentage of state's allowances placed in new-unit set-aside pool	Set aside for new units is 5% for 2009-2014; 3% for 2015 and thereafter. New unit allowances may need to be pro-rated if not enough allowances for all new units in set-aside pool.

4. Emissions Monitoring and Reporting

CAIR requires Part 75 monitoring for NOx and SO2. Monitoring and reporting begins one year in advance of the implementation dates. Those dates are shown in Table 5. Reporting is consolidated and units are to submit one quarterly report containing all information for applicable programs.

TABLE 5
TRADING PROGRAM REPORTING DATES

Trading Program	Date of Initial Reporting Requirement
NOx Annual	January 1, 2008
NOx Ozone Season	May 1, 2008
SO_2 Annual	January 1, 2009

5. Allowance Transfers

There is unrestricted trading of allowances within each CAIR program. Inter-pollutant trading is not permitted. NOx allowance transactions require only seller signature (SO_2 transfers require signatures of both parties). As was the case in both the Acid Rain Program and NOx SIP Call, an EPA-administered electronic data system will be used. The NOx Allowance Tracking System (NATS) was used in the existing NOx Budget Trading Program. EPA oversees all transfers and deductions of NOx allowances in the existing NOx Budget Trading Program. Only parties with a NATS trading account can hold and sell NOx allowances. The current data system is undergoing a re-engineering process prior to CAIR compliance deadlines.

6. Treatment of CHP

The CAIR model rule provides thermal credit for CHP facilities that went on line starting 1 January 2001. However, the approach is inconsistent with the rest of the rule and precedent examples of allocation for CHP. The typical approach is to provide the normal allocation for electric output and then add an allocation for the equivalent value of the thermal output. In the model rule the converted heat input for CHP facilities with a boiler/steam turbine is the total steam output of the boiler divided by 0.8. This is a reasonable estimate of the actual heat input, but it does not account for inefficiency of conventional electricity generation. It basically treats the CHP boiler as a simple steam generator. For combustion turbine CHP facilities the model rule calculates converted heat input as the electric output of the combustion turbine times 3413 Btu/kWh plus the recovered thermal energy divided by 0.8.

a. Energy Efficiency Renewable Energy Set-Aside

States may elect to have an energy efficiency/renewable energy (EERE) set-aside. This set-aside creates a separate pool of allowances that states can allocate to EERE projects to provide incentives for their growth. The EERE projects can sell the allowances, providing them with an economic benefit for their “clean” attributes and subsequently a market-based incentive. States have used this in the NOx SIP call, setting aside anywhere between 3-5% of the allowance pool in the EERE set-aside. Of course the number of remaining allowances available for the main allocation must then be adjusted. Unused allowances in the EERE set-aside are usually redistributed to the sources in the main program. States must clearly define eligible EERE projects with respect to type, size and vintage. Usually only new projects are eligible (most likely starting on the CAIR promulgation date). Some states include CHP facilities less than 25 MW in the set-aside. Some have allowed very efficient fossil-fueled plants in the main allocation to receive part of the EERE set-aside. This can create an incentive for large CHP. EPA has developed several guidance documents on the allocation of the EERE set-aside.

b. Allocation

For existing units, the EPA approach is a fuel-weighted, heat-input allocation. An existing unit is defined as a unit having commenced operation prior to 2001. The baseline heat input for each unit is the three highest years of weighted heat input from 2000-2004. That period of time is referred to as the baseline period. The heat input is weighted by fuel adjustment factors, 1.0 for coal-fired units, 0.6 for oil-fired units and 0.4 for other affected units. This approach awards inefficient plants with more allowances for the same energy output than more efficient plants producing the equivalent amount of energy but with less fuel. The fuel adjustment factors have been a point of controversy.

EPA uses an output-based ‘converted input’ method for allocating allowances to new units with some thermal credit for CHP. A new unit is defined as one that commences operation on or after 1 January 2001. The baseline heat input for new units is based on a unit’s gross electrical output converted to a nominal heat input. The converted nominal heat input is the average of the unit’s highest three years of gross electric output in the baseline period converted to heat input using a heat rate of 7900 Btu / kWh for coal units and 6,675 Btu / kWh for other fuels. The baseline period for new units is the first five full years of operation. This converted heat input (not adjusted for fuel as is the case for existing units) is used to allocate allowances for 2001 and later units from the same pool as the pre-2001 existing units. The rule has a modified baseline formulation for CHP facilities online beginning in 2001. This formulation is intended to give credit for the thermal as well as electric output. For boiler based CHP facilities, the baseline heat input is calculated as the total thermal output of the boiler divided by 0.8. For combustion turbine-based CHP facilities, the baseline heat input is calculated as the electricity output of the combustion turbine converted to heat input at a rate of 3413 Btu / kWh plus the thermal output divided by 0.8. This allocation method is not realistic, as it assumes 100% fuel-to-electricity conversion efficiency.

In the case of CHP, a more appropriate allocation would be based on both the electric and thermal outputs and respective efficiencies (i.e. “double benchmarking”). Under output based regulation, the allocation is proportional to energy (electricity and thermal output) produced rather than heat input - efficiency is rewarded. In a program with a one time, permanent allocation, like the CAIR model rule, the incentive provided by output-based allocation will only affect new plants entering the program. In an allocation system that is updated periodically, an output-based system provides efficiency incentives to all plants. Also relative to the model rule, a fuel-neutral output-based approach would be an improvement because it treats all vintages and all fuels the same.

C. Summary of State Allocation Plans

Of the 28 states in the CAIR region, 21 states have a draft rule either out for public review/ comment or completed. Annex III provides a status of state rules.

V. Federal Greenhouse Gas Proposals

With the new Democratic leadership, the current Congress has made climate change and greenhouse gas emissions a priority. It remains unclear whether any final legislation will emerge from the initial flurry of legislative proposals and hearings. Interested parties must consider whether to get involved in the debate now or risk being left out as the process inevitably moves forward. Private industry has also begun a crucial new dialogue with Congress, working lately to develop a pragmatic and nationwide approach to climate change[xi]. Several significant legislative proposals mandating greenhouse gas emissions caps are already under serious consideration in the 110th Congress, with as many as a dozen more climate change plans expected.

Committees in both Houses of Congress have been holding hearings and requesting industry input on Climate Change and issues to be considered in a possible national carbon cap and trade program. From the perspective of CHP, an allocation distribution that is fuel neutral, updating, and output-based, and that provides credit for thermal energy rewards the greater efficiency of CHP and encourages investment in new generating technologies.

VI. Impact of Massachusetts et al vs. EPA

On 2 April 2007, the US Supreme Court released its ruling in the case of Massachusetts vs. the Environmental Protection Agency (EPA) [xii]. The decision is projected by some to have far-reaching impacts on regulating greenhouse gases in the US.

Massachusetts, 11 other states, and 13 environmental groups sued the EPA for not regulating the emissions of greenhouse gases for the transportation sector. The Court ruled that greenhouse gas emissions are pollutants and ordered federal environmental officials to reconsider their refusal to limit emissions from new cars and trucks. The ruling improved the odds that Congress would take action on comprehensive legislation to address Climate Change.

EPA had argued that it did not have the authority under the Clean Air Act to regulate CO_2 or other greenhouse gases. The Court challenged EPA's refusal to regulate CO_2 as an air pollutant under the statute and found that it fits within the statute's broad definition of an air pollutant. The Court also ruled that "under the Act's clear terms, EPA can avoid promulgating regulations only if it determines that greenhouse gases do not contribute to climate change or if it provides some reasonable explanation as to why it cannot or will not exercise its discretion to determine whether they do."

The opinion certainly opens the door to economy-wide federal regulation of greenhouse gases under the Clean Air Act. The reasoning in the decision would appear to also apply to EPA's decision not to impose controls on greenhouse gases for electricity generators. It is likely to serve as a catalyst for comprehensive federal climate change legislation. Further state action on climate change, including California AB 32, will add further pressure for a more uniform federal program.

VII. US EPA Guidance on Cap and Trade Program Design

The US EPA has published guidance on emissions cap and trade program design and operation in, *Tools of the Trade: a Guide to Designing and Operating a Cap and Trade Program for Pollution Control.* The guidance reference covers SO_2 and NOx trading programs, but it is sufficiently generic to apply to various pollutants and environmental concerns.

In the design and administration of an EPA-managed GHG cap and trade system, EPA is likely to provide model rules and guidance consistent with prior federal programs and the lessons learned from those precedents. That includes the SO_2 Acid Rain, the NOx SIP Call Program and the CAIR markets described in this report. The main characteristics of those programs include:

- Source-based program
- Focus on large electric generators
- Flexibility to states with regard to allowance allocations, set-asides, off-set eligibility, and opt-in provisions.

While heat input-based allocations for existing sources have been used in prior national programs, EPA gives new CHP facilities credit for thermal energy output in output-based allocations. EPA has issued guidance on the implementation of output-based regulations that recognize and value efficiency.

VIII. Policy Recognition of CHP Benefits – World Best Practice

A. Selected CHP Incentive Measures

In addition to programs focused on using CHP to reduce carbon emissions as part of the EU ETS, a growing range of countries have also developed other programs intended to realize the other benefits from increased development of new CHP resources. Some data on CHP capacity development around the world is provided in Annex IV.

1. The Netherlands

The Netherlands, perhaps more so than any other nation, has a strong track record of legislative and policy mechanisms for the promotion of CHP. In terms of real CHP market growth, the Netherlands has achieved dramatic success through direct policy intervention on the basis of a clear CHP strategy.

The experience with the implementation of CHP has been a remarkable success. The reasons for this, in summary, are:

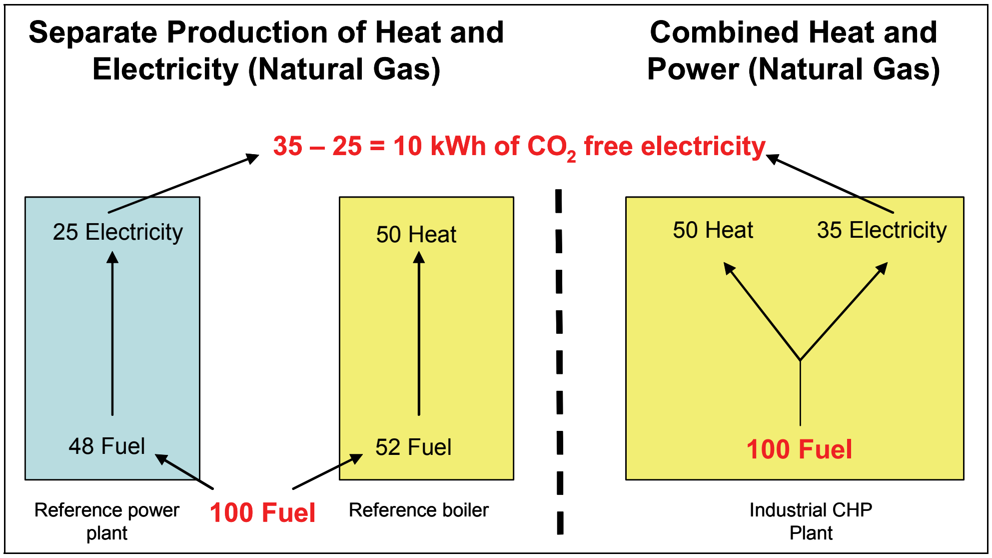
- The governmental sponsor of CHP is the Ministry of Economic Affairs (MEA), which also has responsibility for energy market regulation and management. Once the MEA had taken the view in the early 1990s that the electricity industry monopoly needed reform, it simultaneously introduced regulatory incentives for CHP and separated the generating companies from the distribution companies (which were then free to invest in CHP in order to compete with generation companies). The combined impact was dramatic.
- During this period, the country was introducing some of the most progressive energy efficiency and environmental policies of any country in the world. A series of voluntary industry energy efficiency agreements, involving both electricity distributors and consumers, provided a substantial additional incentive for CHP.
- The creation of Projektbureau Warmte-Kracht, an independent agency to support project investment, ensured that the growing industry interest in CHP could be fed with high quality technical and financial guidance that, in turn, catalyzed the development of many industrial and commercial projects.
- From the end of the 1980s and through the following ten years, the government maintained a long-term commitment to CHP and towards the achievement of its 2000 target for growth.

The Blue Certificate Scheme. Since the end of the 1990s, government support has decreased. Nevertheless examples of contemporary laws which show promise for promoting CHP do exist. In 2004, a new scheme was established whereby carbon credits are earned for all CHP projects that qualify.

The system, known as the Blue Certificate System, applies to all power generated from CHP plants regardless of whether the power is fed into the grid or used onsite. The scheme establishes a methodology for attributing carbon benefits to CHP so that the benefits can be rewarded. Each kWh of ‘free carbon’ benefits earns a payment of €c2.6.

It is estimated that around one third of electricity supplied by CHP in the country will be identified as carbon-free and will therefore benefit from the premium. As the national market presently stands, however, it is expected that the scheme will stabilize the commercial viability of existing plants but is not sufficient to incentivise new plant investment. Figure 4 illustrates how the carbon benefit will be calculated.

FIGURE 4
CALCULATION OF CHP BLUE CERTIFICATES



COGEN NEDERLAND, 2003

2. Portugal

Portugal has developed a CHP-based tariff system, one of the most innovative and positive in the world, that has made a significant impact in developing CHP market growth in that country. The tariff for CHP export electricity is based on the avoided costs of central production in respect of:

- New investment capital required to increase production capacity.
- Electricity production (fuel, operation and maintenance).
- Electricity transmission and distribution (new investment in networks, network operation and maintenance, losses).
- Carbon dioxide emissions.

The tariff applies over the whole lifetime of the installation and producers of CHP (and renewables) have the right to sell their electricity to the grid at a tariff based on the structure shown in the formula below:

CHPt = [Ft + Vt = Et] x Nf

Where:

- CHPt = The monthly payment for CHP export electricity supplied to the network.
- Ft = A fixed term that includes avoided costs of new investment in electricity production and CHP plant availability.
- Vt = A variable term that includes the avoided costs of fuel, operation and maintenance (O&M), network investment and network O&M.
- Et = An environmental term that includes avoided CO_2 emissions.
- Nf = A network factor that takes into account the avoided network losses.

Features of the system include:

- The avoided CO_2 is compared with the most efficient technology for new power capacity, a CCGT with an efficiency of 55% and emissions of 370 kg CO_2 / MWh.
- The performance of CHP is based on the concept of Electrical Equivalent Efficiency (EEE), which is defined as EEE = E / (C – (T/0.9)), where:
    - E = useful electricity
    - C = fuel
    - T = useful thermal energy
- The EEE must be greater than 55% for natural gas-fired CHP, >50% for fuel oils, and >45% for plants that burn more than 50% biomass annually. The prices are indexed to oil prices (and thus export prices have increased in line with gas prices in recent years, since gas and oil prices are linked in Europe).

This policy has been extremely effective in Portugal in safeguarding the economic performance of existing CHP plants and stimulating new capacity to come on stream.

3. Belgium – Wallonia

The Walloon green certificate scheme is one of the best support mechanisms for CHP in Europe. The scheme is based upon avoided CO_2 emissions, with one certificate issued for every 456 kg of CO_2 avoided. CO_2 savings calculations for cogenerated electricity are based upon the following references:

- 456 kg of CO_2 emitted per MWh by a power plant at 55% efficiency.
- If there is a natural gas distribution grid: 90% efficient boiler emitting 279 kg CO_2 per MW.
- If there is no gas distribution network: 90% efficient domestic fuel boiler with 340 kg of CO_2 emitted per MW.

The CO_2 savings ratio is the difference between the amount of CO_2 emitted by the separate production of an equivalent quantity of electricity and heat and the amount emitted by a CHP installation, divided by the CO_2 emitted by the reference unit for the same given electricity production.

Eligible plants receive green certificates for a period of ten years. Any electricity provider in the Walloon market must present CWaPE (the regional Regulator) each quarter with a quota of green certificates proportional to the amount of electricity sold. The quota has been steadily increasing from 3% in 2003 to 7% in 2007 and has been set at 12% for 2012. Certificates have been trading at €92 for over 2 years and certificates are awarded for all the electricity produced, including electricity that is consumed on-site.

For 20 MWe+ plants, CO_2 savings attributable to all but the base 20 MWe are calculated without taking heat production into consideration, which in effect cancels the benefits of cogeneration when calculating green certificates. This is a major barrier for larger plants.

The estimated benefits are:

- 40 MWe gas turbines – €12 / MWh (over 10 years)
- 1 MWe gas engines – €30 / MWh (over 10 years)
- 1 MWe biogas engine / wood turbine – €190 / MWh (over 10 years)

4. Belgium – Flanders

The Flemish scheme for CHP installations rewards PES. Eligibility is restricted to plants with a PES of at least 5% (soon to be 10% for schemes larger than 1 MWe in accordance with the CHP Directive) and, unlike Wallonia, there is no ceiling on the plant's installed capacity. The owners of CHP plants receive 'CHP certificates' in proportion with their PES gains (and can also receive green certificates provided the CHP unit is fuelled by renewable energy sources). The number of certificates issued for each plant declines after the first 4 years and the required amount of cogenerated electricity to be sold is increased yearly until 2012. Penalties for missing certificates of up to €45 / MWh ensure that the certificates have a market value. Certificates are valid for 5 years but cannot be banked.

The estimated benefits are as follows:

- 40 MWe gas turbine – €17 / MW (over 10 years)
- 1MWe gas engine – €41 / MW (over 10 years)
- 1 MWe biogas engine – €115 / MWh (over 10 years)

IX. Key Conclusions

CHP is increasingly recognized as a proven and cost-effective option for reducing carbon emissions in the electricity, industrial and commercial sectors. As an example, the most recent international endorsement of its potential is the May 2007 Inter-governmental Panel on Climate Change Working Group III Report on solutions to tackle climate change.

An important reason why CHP, a decentralized form of electricity and heat generation, has remained at the margins in most countries until now is that the centralized model of electricity generation and supply has predominated for decades. This dominance is based on the absence, until relatively recently, of technical alternatives to large power plants sited remotely from consumers and which cannot recover waste heat.

The emergence of smaller gas turbines and engines now means that the technical and economic opportunity for high efficiency CHP can be widely realized today, were it not for long established market structures designed to accommodate the centralized system.

These market structures are beginning to evolve in many countries but until they have changed further, CHP development will often require the implementation of policy and / or regulatory measures designed to reflect its many efficiency and environmental benefits. There are now many examples of such measures around the world, mainly in Europe which has traditionally placed priority on high environmental performance in the energy sector. Some of these examples are highlighted in this report and include:

- The double benchmarking allowance allocation arrangements applied by, among others, Germany and Italy in the EU ETS.
- The CHP strategy implemented in the 1990s in the Netherlands, including market-based incentives for energy supply companies to invest in CHP plants in order to increase competition and energy efficiency in the electricity market. The growth in CHP investment that has taken place since then has conferred several material benefits to the country, including reduced carbon emissions, higher efficiency of natural gas use and lower electricity network losses.

Equally, there are a small handful of examples of measures whose aim is carbon emission abatement in mind but whose design does not take account of the complex nature of CHP's position in the energy supply chain – CHP sits comfortably neither on the supply side nor on the demand side, a feature that can lead to its oversight by policymakers.

The most notable recent example of this is the EU ETS, whose basic design does not take into account the significant *net* emission savings brought about by CHP and instead penalizes it for the increase in *site* emissions that follow installation of a CHP plant.

Fortunately, a growing number of EU Member States have recognized this drawback and are designing allowance allocation plans that ensure the efficiency benefits of CHP are fairly reflected. Again, examples of these plans are given both in the main report and in Annex I. In summary therefore, international experience, as described in this report, suggests strongly that:

- The energy efficiency and environmental benefits of wider CHP use are well proven.
- There is now a well documented range of international experience of effective policy and regulatory measures designed to enable CHP to reach its market potential.
- GHG trading systems can be designed both to bring about low cost, market-based reductions in carbon emissions while simulating CHP market development.

Annex I – EU ETS Phase I and II NAP Highlights

Phase I

NAP I	Austria	Denmark	Germany
General			
Basic principles of allocation	Sector budgets are calculated from historic emissions multiplied by a growth factor, reduction potential factor and compliance factor. Installation allocations are then made from these budgets based upon the historic share of emissions multiplied by a correction factor and compliance factor.	Three sectors are defined, heat production, electricity production and all other ETS activities. Sector budgets for heat and electricity sectors are calculated based upon actual output. The sector budget for all other activities is determined based upon historic emissions.	Allocations are made directly to installations based upon historic production or emissions data, modified by a standardized compliance factor determined by the type of installation.
How are baselines established	Baselines are based on 2003 emissions.	Based upon output or emissions depending on sector between 1998-2002.	Based upon average emissions 2000-2002.
CHP Installations Included in the Scheme			
Definition of CHP	CHP should provide a 5% primary energy saving over separate heat and electricity production.	No definition provided in NAP.	Defined in a 2002 Act referred to in NAP.
Is CHP from a range of sectors included in the scheme?	Yes	CHP is considered as part of both the electricity (for electrical output) and heat (for heat output) production sectors.	Yes
Allocation Methodology for Incumbent Plant			
General allocation methodology	Allocations are made to installations based upon their share of historic emissions, reduction potential factor and a compliance factor.	For the electricity sector a total cap has been specified, with allocations made within this budget based upon historic production modified by a growth factor. The heat sector's budget is calculated based upon historic production modified by a compliance factor and growth factor. Allocations are made within this budget based on the installation's share of historic production.	Allocation is based on baseline emissions multiplied by a compliance factor of 0.9709. Heat and power Installations receive an additional free bonus allocation of up to 27 allowances per GWh of electricity produced.

NAP I	Austria (cont)	Denmark (cont)	Germany (cont)
Have CHP plant been treated any differently from non-CHP plant?	The compliance factor for CHP installations is half as punitive as non-CHP plants.	No, allocated separately for heat and electricity production.	CHP receives allocations based upon electricity production multiplied by a CHP bonus factor.
Does the allocation to CHP vary by sector?	Compliance factors vary by sector, therefore a CHP installation's allocation may change depending upon the host sector.	No	No
Does the allocation methodology differentiate between good quality/efficient CHP	No distinction for incumbent plant. For new plant, a distinction is made as part of benchmarking process.	No distinction for incumbent plant. For new plant, a distinction is made as part of benchmarking process.	No distinction for incumbent plant. For new plant, a distinction is made as part of benchmarking process.
Allocation Methodology for New Entrant CHP Plant			
General allocation methodology	Allocated using standardized benchmarking.	Allocation is based on separate electrical and heat benchmarking and allowances are calculated separately for each.	New entrant can obtain allowances from old power generating installations, which are shut down. In cases where no transfer is possible, a double benchmark is applied. The double benchmark provides allocations based upon both installed heat and electricity capacity.
Does the allocation to CHP vary by sector?	NER varies by sector, the NER available to CHP may depend on what sector it is in.	Allocations are made in proportion to a plant's heat and electrical capacity. Electrical capacity for CHP is measured when the plant is operating at maximum heat load.	No sectors as such, however different benchmarks are applied to different types of installation – for example load factors differ with energy plant technology type or manufacturing process.
Do CHP installations have preferential access to the NER?	No	No	No
Has CHP plant been treated differently to non-CHP plant?	Allocation methodology not specified for CHP, so it is unlikely that CHP is treated differently.	No	Yes, through double benchmarking.
Comment on Treatment of CHP	The compliance factor bonus ensures that CHP plants will receive a greater allocation than non-CHP plant – however this measure is biased towards older less efficient plant, with new plant benefiting less.	As output heat and electricity are allocated separately, CHP is treated logically and fairly, receiving a greater number of allocations for a given level of emissions than separate heat and power production facilities.	The CHP bonus for existing plants is positive. Double benchmarking heat and electricity output ensures new CHP receives a good allocation. For new entrants, the transfer rule provides a considerable incentive to switch from old power plants to new CHP. However, because the NER is small, the benefit is limited.

NAP I	The Netherlands	Poland	UK
General			
Basic principles of allocation	Allocation is based on energy output and benchmark efficiencies. Each sector has a specific growth factor, and compliance factor to leave allocation spare for new entrants to the sector. A general compliance factor of 0.97 is applied to all sectors.	Sector budgets are determined based upon historic emissions modified by a growth factor. Allocations are made to individual installations based upon their share of historic emissions.	Sector budgets are calculated based upon historic emissions, with a compliance factor applied. Installation level allocations are then calculated based upon the share of the sector budget multiplied by the sector cap.
How are baselines established	Based upon average emissions calculated from output between 2001 and 2002.	Average of annual emissions 1999-2002 excluding the lowest year.	The baseline is established by taking the average annual emissions between 1998 and 2003, excluding the lowest year.
CHP Installations Included in the Scheme			
Definition of CHP	Defined as either stand-alone or part of an industrial process.	Installations which produce electricity and heat in a combined system and demonstrate an energy efficiency of at least 65%.	Definition of a Good Quality CHP plant provided in Annex to main NAP.
Is CHP from a range of sectors included in the scheme?	Yes	Yes	Yes - installations are considered part of their industrial host sector.
Allocation Methodology for Incumbent Plant			
General Allocation Methodology	Installations are allocated within their sector based upon average output during the baseline period multiplied by benchmarks.	Allocations are made to installations based upon their share of historic sector emissions.	Sector budgets calculated using grandfathering based upon historic emissions from baseline years. Compliance factor is applied so budgets are less than cap. Allocations are made to installations from the budget based upon their share of sector historic emissions.
Have CHP plant been treated any differently from non-CHP plant?	Most large CHP is treated as part of the Power Sector or the Joint Power / Industry Sector. Allocations are made based upon actual heat and electricity output during the baseline period. Most smaller CHP is treated as part of its host industrial sector and is also allocated based upon actual output during the baseline period.	CHP installations receive a bonus allocation of 50% of their potential emissions saving.	No, treated in the same way as all other sectors with allocations based upon historic emissions.

NAP I	The Netherlands (cont)	Poland (cont)	UK (cont)
Does the allocation to CHP vary by sector?	Industrial plant is benchmarked as part of an energy efficiency covenant or long term agreement which requires companies in the Netherlands to be among the 'world top' in terms of energy efficiency.	No	Yes, installations are treated as part of the host sector, therefore allocations can differ depending upon which sector the CHP installation is operating in.
How have CHP plant been classified into sectors?	Stand-alone plants are treated separately, industrial plant are part of the industrial sector for which they produce energy.	Considered part of host sector.	Considered part of host sector.
Does the allocation methodology differentiate between good quality/efficient CHP?	Yes, through the use of the benchmarking approach and the existing industrial covenants.	Yes, the energy efficiency of the plants determines the allocation.	Only for new entrant CHP.
Allocation Methodology for New Entrant CHP Plant			
General Allocation Methodology	Double benchmarking using partly standardized benchmarks.	Allocations based upon production plans, emissions factors and standardized BAT benchmarking.	Standardized BAT benchmarking of the electrical efficiency of CHPQA qualifying CHP plants.
Do CHP installations have preferential access to the NER?	No	No	Yes – good quality CHP has preferential access.
Have CHP plant been treated differently to non-CHP plant?	Yes, through benchmarking of heat output against separate heat generation.	No	No
Comment on Treatment of CHP	This is one of the most supportive NAPs for industrial CHP in Phase I on the basis of the favourable benchmarks. CHP was a 'winner' from this NAP.	The CHP bonus is certainly helpful and should allow CHP plant to receive greater allocation than conventional plant.	CHP plant allocation is highly dependant upon the industrial sector occupied. Whilst there is a ring fence for new high quality CHP there is little other support provided.

Phase II

NAP II	Belgium: Flanders	Germany	Italy
General			
Basic principles of allocation	Allocations are made directly to installations with no sector budgets used. For non-energy sector CHP i.e. onsite industrial CHP, allocations are provided as part of a companies allowance as part of a 'covenant agreement' between business and government. It ensures that a CHP installation receives 100% of necessary allocations. For installations not part of the covenant, allocations are issued based upon emissions data from 2005 with a compliance factor applied. In the energy sector, allocations are based on the capacity, load factor and a uniform BAT benchmark of 0.359 tCO_2 / MWh.	Grandfathering for existing plants. Double benchmarking for new plants. Existing plants are allocated based upon average emissions during 2000 – 2005 multiplied by a compliance factor. New plants are allocated based upon BAT double benchmarking and projected output.	Four sectors are defined: Energy activities (including refineries), production and transformation of metals, mineral products industry and others. Reductions will be concentrated in the power and refinery sectors, since these sectors are considered as having a bigger potential for emissions reduction.
How are baselines established	2005 emissions.	Based upon average emissions between 2000-2005.	2005 emissions.
CHP Installations Included in the Scheme			
Definition of CHP	None given.	None given.	In order to be considered CHP, a plant must provide a certain level of energy savings, calculated by an Energy Savings Index (Indice di risparmio energetico, IRE).
Is CHP from a range of sectors included in the scheme?	Yes	Yes	Yes
Allocation Methodology for Incumbent Plant			
General allocation methodology	Allocations are made to plant operating in the energy sector using the standard benchmark. Allocations are made to plant in other sectors via the covenant agreement.	An allocation is made based upon average emissions between 2000 – 2005 multiplied by a compliance factor. The CF is 0.85 for energy sector installations and 0.9875 for non-energy installations, including CHP.	CHP plants are considered as either energy plant (stand alone) or as part of an industry sector (industrial CHP). Allocations to CHP plant are based upon heat and electricity output during the baseline year.

NAP II	Belgium: Flanders (cont)	Germany (cont)	Italy (cont)
Have CHP plant been treated any differently from non-CHP plant?	Not in the energy sector. In the non-energy sector, allocations are provided as part of the covenant agreement. For non -energy CHP not covered by the covenant agreement a compliance factor of 1 is used in place of the standard 0.85.	CHP receives a beneficial correction factor.	Yes, the trend reduction factor (similar to the compliance factor) reduces allocations to non-CHP plant from 2009 onwards. Allocations to CHP plants are based upon double heat and electricity benchmarks.
Does the allocation to CHP vary by sector?	Yes as described above.	No	Yes. Allocations can vary depending upon the CHP plant's host sector.
How have CHP plant been classified into sectors?	Only divided into energy and non energy sectors.	They are all treated the same.	A distinction is made between the power sector and other industry related sectors.
Does the allocation methodology differentiate between good quality/efficient CHP	No	No	Yes as part of the benchmarking process.
Allocation Methodology for New Entrant CHP Plant			
General allocation methodology	A new entrant is defined as a plant which received an environmental license after the NAP II proposal was submitted for review by the EU Commission, or started operation after 1 December 2006.	Allocations are made based upon projected energy output and fuel specific double BAT benchmarks, using the same method as NAP I.	Energy plants are allocated based upon technology benchmarks and expected output (based on capacity and load factor).
Do CHP installations have preferential access to the NER?	No	No	No
Have CHP plant been treated differently to non-CHP plant?	Same treatment as existing plants.	No	Yes, new entrant CHP installations are double benchmarked based upon heat and electricity outputs.
Comment on Treatment of CHP	CHP operating in the electricity sector is fairly treated. If the plant is part of the covenant agreement then it should receive 100% of necessary allocations. If not part of the covenant a correction factor of 1 is applied to historic emissions data. Overall this is a very supportive NAP for non-electricity sector CHP.	Supportive for new CHP as the double benchmark of heat and electricity will provide over-allocation to new plant. Existing plant receives a beneficial compliance factor.	This is a significant improvement upon the Italian NAP I, with double benchmarking using favourable benchmarks, together with a reduced 'compliance factor' equivalent after 2009.

NAP II	The Netherlands	The UK
General		
Basic principles of allocation	No sector budgets are used; allocations are made directly to individual installations. For existing plants, allocations are made based upon the historical emissions of the plant, with a compliance factor applied.	As with NAP I, allocations are made to industrial sectors based upon historic emissions. A growth factor and compliance factor are then applied. Allocations are then made from sector budgets to individual installations based upon individual facilities' share of historic emissions.
How are baselines established	Based upon average emissions between 2001 and 2005, a growth factor of 1.07% per year is used for the period 2006 – 2010.	Sector budgets are determined based upon 2000 – 2003 emissions.
CHP Installations Included in the Scheme		
Definition of CHP	Based on those plants represented in the government – industry covenants.	Refers to Good Quality CHP definition.
Is CHP from a range of sectors included in the scheme?	Yes.	A Good Quality Combined Heat and Power (GQ CHP) sector has been created specifically for plant that qualify as 'high quality' under the UK CHP Quality Assurance program.
Allocation Methodology for Incumbent Plant		
General Allocation Methodology	Allocations are made based upon historical plant emissions multiplied by a growth factor, an energy efficiency factor (using benchmarks) and a generic compliance factor.	Allocation as a share of sector budget based upon plant's share of historic emissions.
Have CHP plant been treated any differently from non-CHP plant?	CHP receives an allocation based upon a fuel specific electricity and heat benchmark.	Yes, treated as its own sector and so avoids compliance factor altogether, ie is issued with full allocation.
Does the allocation to CHP vary by sector?	See NAP I.	Non-qualifying CHP is not part of new CHP sector.
How have CHP plant been classified into sectors?	See NAP I.	GQ CHP has its own sector, if a CHP plant only partially qualifies, then that part of its capacity that is not GQ will be considered part of the sector to which it belongs.

NAP II	The Netherlands (cont)	The UK (cont)
Does the allocation methodology differentiate between good quality/efficient CHP	CHP plants receive additional allocations if their efficiency is better than benchmark efficiencies	Yes. Non-qualifying CHP is treated less favorably.
Allocation Methodology for New Entrant CHP Plant		
General Allocation Methodology	New plants get free of charge allowances. The quantity of allowances will be based on expected output and double BAT benchmarks.	New GQ CHP receives allocations based on standardized CHP benchmarks and standardized load factors.
Do CHP installations have preferential access to the NER?	No	A significant part of the NER (27.5 million of approximately 81.5 million allowances) is specifically ring-fenced for new entrant GQ CHP.
Have CHP plant been treated differently to non-CHP plant?	See NAP I.	New GQ CHP will be allocated at 100% of the benchmarked amount of allowances, compared to 90% for new entrant boilers, other generators and non-qualifying CHP plants. The standardized load factors are regarded as too low for CHP operation in practice.
Comment on treatment of CHP	See NAP I. As with NAP I, the double benchmarking arrangements are favourable to CHP and designed to reward 'early movers'.	By creating a separate CHP sector, CHP plants will receive fairer overall treatment than if considered part of host sectors, as it was for NAP I. Only including 'good quality' CHP in additional support measures ensures that efficient CHP is rewarded. However, the standardized load factors are unhelpfully low.

Annex II – RGGI State-by-State Summary

Connecticut

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The CT DEP (Department of Environmental Protection) is currently holding stakeholder workgroup meetings to help map out regulatory development of the state's RGGI rule according to the following schedule:

- December 14, 2006 – Focus: Overview of RGGI rule.
- February 15, 2007 – Focus: U.S. GHG Offset Acquisition Initiative.
- April 26, 2007 – Focus: Summary of draft CT rule.

The DEP released a first draft pre-proposal of CT's RGGI rule in late April 2007. The DEP is hoping to issue an official proposed rule by mid-summer and have a final rule completed by late December 2007.

Implementation of RGGI in Connecticut is an important part of the state's overall Climate Change Action Plan [http://www.ctclimatechange.com], a legally non-binding effort to reduce the state's emissions. The Plan, which promotes a variety of regulated and voluntary programs and proposals, recommends that Connecticut participate in RGGI's cap-and-trade program.

According to Chris Nelson, the DEP is "strongly considering doing a 100% auction," though debate on the state's allocation method is in the early stages. The DEP is still trying to determine the best mechanism for participating in an auction and for making consumer benefit allocations. Governor Jody Rell recently announced that she would support a bill to allow the state to do a 100% auction. The proposed legislation would allow the state to allocate to a proposed new Department of Energy that would then issue allowances (much like the NYSERDA role proposed by the New York DEC – Department of Environmental Conservation). Connecticut does not currently have a centralized agency to handle its energy and energy-related issues.

Delaware

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Delaware has not yet commenced its rulemaking process. According to Phil Cherry, state officials expect to initiate stakeholder group meetings "in the Spring," and would like to have the final rulemaking completed by the end of 2007 ("though that might slip into 2008").

Internally the DE DNR (Department of Natural Resources) is discussing all of the key issues (i.e. percentage allocations, how to allocate versus auction, etc.). The agency hopes to "wrap up internal discussions in the next month" before engaging stakeholders and beginning the rulemaking process. "Right now, it's too early to talk about [which way Delaware is leaning on implementation issues]."

With regard to CHP, Phil Cherry says that RGGI is "not intended to aid that kind of resource." RGGI stakeholder chose 5-6 particular kinds of offsets for initial eligibility. Regional RGGI stakeholders have agreed that they will examine additional offset types in the future. The big challenge is that a regional program like RGGI must have comparability in states for offsets (e.g.

For Delaware to allow for CHP offsets without recognition and agreement by other states would create a different currency). Phil Cherry recommends we contact him again in May 2007 for an update on the status of Delaware's approach.

Maine

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The Maine DEP (Department of Environmental Protection) completed a series of public roundtable forums concerning the state's participation in a RGGI emissions cap and trade program on December 19, 2006. It has been determined that just six power plants in Maine will be affected by RGGI.

Legislation (L1851) was introduced in April 2007 to authorize the state to participate in RGGI, and to implement the Model Rule. The proposal calls for all allowances to be auctioned. Most importantly, the legislation proposes to create a set-aside of the state's annual emissions for CHP systems sited at industrial facilities. The set-aside would be limited to the amount of power consumed on-site, and not include power exported to the grid.

Massachusetts

Contact:

Bill Lamkin, Massachusetts DEP and RGGI Staff Working Group Subgroup Chair of Model Rule: 978.694.3294; William.Lamkin@state.ma.us

Massachusetts is running RGGI stakeholder meetings on RGGI according to the following schedule:

- March 5, 2007 – Focus: Transitioning from 7.29 (a pre-existing CO_2-limiting arrangement) to RGGI.
- March 12, 2007 – Focus: Allowance Auctions.
- Early and mid-April 2007 - Duplicate meetings held in different geographic locations.

The input from the stakeholder meetings will influence decisions in the MA-specific RGGI rule. The MassDEP (Department of Environmental Protection) intends to issue its proposed rule to implement RGGI during the summer/fall 2007, and to have a finalized rule by early 2008.

Many state-specific issues are still being debated. However, oratory from Governor Deval Patrick perhaps offers clues as to the direction Massachusetts might take. During the January 18, 2007 RGGI signing ceremony, the **Governor announced that the state would auction 100% of its allowances, and use the funds generated by those sales**—an estimated $25 million-$125 million/year, depending on the market price of the allowances—**to fund** energy efficiency, demand reduction, renewable energy programs, **and combined heat and power (CHP) projects.**

The biggest challenge Massachusetts faces is in transitioning from its pre-existing CO_2-limiting regulatory framework (310 CMR 7.29, at http://www.mass.gov/dep/air/laws/regulati.htm) to RGGI. The state has already adopted regulations that establish CO_2 limits for six power plants, responsible for 70% of the state's stationary power plant emissions. By contrast the RGGI Model Rule will affect 32 facilities, requiring, among other things, a recalculation and redistribution of allowances.

7.29 is not a cap-and-trade program; rather, it imposes emission standards, a cap, individually on each of the six highest emitting electric generating facilities in Massachusetts. The CO_2 cap standard was made effective on 1 January 2006; an annual CO_2 "rate" standard of 1,800 pounds CO_2/MWh is currently intended to be made effective on 1 January 2008. To comply with 7.29 CO_2 standards, regulated generators have the option to either:

- Directly reduce stack emissions, or
- Earn Massachusetts (MA) GHG credits by establishing projects that reduce, avoid, or sequester emissions, or
- Pay into an Expendable Trust (available only if certain triggers are met).

As such, MA GHG credits **are not equivalent to** RGGI CO_2 offsets or allowances. Major differences hinge on compliance limits and types of qualified offsets. MA GHG credits can be used to demonstrate compliance without limit. RGGI, meanwhile, requires that facilities retire CO_2 allowances and/or CO_2 offsets equal to their CO_2 emissions during each compliance period. It also stipulates that CO_2 offsets can only be used to satisfy a small percentage of a facility's total compliance obligation.

Until RGGI commences, the Massachusetts DEP will continue to implement the CO_2 emissions standards of 7.29, as well as the banking and trading provisions of Appendix B(7). The DEP is warning applicants for MA GHG Credits under Appendix B(7) that they should not presume that the DEP will continue certifying and verifying applications for RGGI-ineligible projects.

Among the questions the MassDEP is working to answer:

- When should MassDEP stop certifying and verifying RGGI-ineligible MA GHG Credits?
- What should be done with unused RGGI-ineligible MA GHG credits once RGGI begins?
  - Option 1: Allow these MA GHG credits to be converted to RGGI CO_2 allowances. This would require MassDEP to set aside a small fraction of MA RGGI CO_2 allowances.
  - Option 2: Allow owners of MA GHG credits to purchase RGGI CO_2 allowances at a discounted rate (preferred by MassDEP).
- From where should CO_2 allowances originate?
  - Option 1: A small one-time set-aside of RGGI CO_2 allowances from MA budget in year 1 that can be exchanged until this set-aside is used up.
  - Option 2: Annually set aside a small number of RGGI CO_2 allowances from the MA budget for a yet-to-be-determined number of years.
- How should MassDEP exchange RGGI-ineligible MA GHG Credits for CO_2 allowances?

Maryland

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Maryland joined RGGI when Governor O'Malley signed legislation on 20 April 2007. . In April 2006, the state passed the Healthy Air Act (HB 189 / SB 154). It requires, among other things, CO_2 reductions at the state's six largest power plants and that Maryland join RGGI by no later than 30 June 2007. According to Gene Higa, it is unlikely that a pre-proposal for the state's model rule will be made public for comment until the end of 2007.

Under the Healthy Air Act (HAA), between July 1, 2006 and January 1, 2008, Maryland Department of the Environment (MDE) is required to study reliability and cost issues that may result from joining the RGGI consortium. To that end, the MDE contracted with the University of

Maryland to conduct an independent study of the economic and energy impacts related to Maryland's potential participation in RGGI. The study [http://www.cier.umd.edu/RGGI/documents/UMD_RGGI_STUDY_Jan07.pdf) was released in February 2007 and a related comment period concluded three weeks later. The comments, from 15 stakeholders, are available at http://www.cier.umd.edu/RGGI/stakeholder_comments.htm.

The study's main conclusions find that joining RGGI would have only a limited, though positive, impact on Maryland's economy and electric power markets. Among the key results:

- Emissions of CO_2 from electricity generators in Maryland will be lower than expected with emissions falling substantially below allocated target levels in 2010. Over the entire forecast horizon, cumulative emissions of CO_2 in the expanded RGGI region, including Maryland, fall by 26 million tons including offsets that reduce GHG emissions in other sectors by the equivalent of roughly 19 million tons.
- A small yet positive impact on the state economy will result (e.g., less than 0.1% of overall Maryland gross state product and employment in all years).
- Electricity prices paid by ratepayers will remain virtually unaffected and small reductions in electricity demand will occur because of greater investment in energy efficiency. The result will be a decrease in statewide electricity bills of more than $100 million in 2010 and more than $200 million in savings by 2025. Over half of these savings accrue to commercial and industrial users, and the average residential electricity bill will see a modest decrease of about $22 per year in 2010.

New Hampshire

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The New Hampshire Department of Environmental Services (NH DES) has been conducting a series of public meetings on RGGI, with future meetings scheduled on an as-needed basis. NH DES has yet to conclusively decide how it will allocate its allotted allowances, whether by auction or otherwise, or on the revenue level it will commit to set asides. DES officials have stated no public preference on any of the outstanding RGGI implementation issues at this time. A RGGI bill will likely be introduced in the legislature during fall 2007, with passage forecasted by mid-2008.

NH DES and the New Hampshire Public Utility Commission are currently working with the University of New Hampshire to evaluate state-specific economic impacts of RGGI. In particular the study is performing an economic analysis of different allocation options, and is expected to be completed in late fall 2007.

New Hampshire is the only state in the group of RGGI participants that does not operate in a fully deregulated market. According to Joanne Morin, the state instead supports a hybrid electricity marketplace that is mostly regulated, but also partially unregulated. For example, Public Service Company of New Hampshire (PSNH) generates 80% of its own electricity, buys roughly 20% on the open market, and can not build/own additional generating assets. Consequently, the state faces the more idiosyncratic challenge of determining the merits of different allowance allocation options.

Morin believes that the merits of a 100% auction hold greater weight in a fully deregulated market, but that they may not be as clear in a partially regulated market like New Hampshire's. In a deregulated market, the revenues from auctioning the allowances for set-asides can be used to fund energy efficiency or CHP projects, which can then, in turn, provide extra benefit by lowering prices and demand. A 100% auction also makes more sense in a deregulated market because the market can incorporate the added cost of allowances and increase overall prices. If a state simply gives away allowances to generators it forgoes any kind of mechanism for compensating ratepayers for that added cost. New Hampshire's circumstances are different, however, since any additional cost of allowances would be a direct cost pass-through and would be added to utility customers' bills.

NH DES is also working to harmonize its Clean Power Act (CPA) with the RGGI model rule. The state's Clean Power Act was signed into law in November 2001; it caps NOx, SO_2, CO_2, and mercury from PSNH fossil-fuel power plants. Compliance is achieved either through direct emission reductions or credit purchases. RGGI will only affect the CO_2 cap stipulated by the CPA and require, among other things, that a greater number of facilities be regulated and that the overall cap be recalculated. Implementation into RGGI will be considered a Phase II cap under CPA.

New Jersey

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New Jersey has held regional stakeholder conferences to obtain public input; there are no additional intra-state stakeholder meetings planned. Currently New Jersey has no official rule development schedule, but it intends to commence rulemaking in 2007 with the goal of finalizing such rulemaking in 2008.

New Jersey Governor John Corzine has publicly stated his intention to explore the auctioning of up to 100% of the state's allocations and to use generated funds to promote energy efficiency and renewable energy projects. According to Chris Sherry, the state also intends to "go significantly above the 25% minimum in terms of consumer benefit allocations."

New York

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The New York State Department of Environmental Conservation (DEC) released a preliminary draft set of rules to implement RGGI in New York on 5 December 2006 [http://www.dec.state.ny.us/website/dar/preproposal.html]. The public comment period on the preliminary rule ends on 13 March 2007.

Much of the pre-proposal issued by NYDEC stems from the RGGI Model Rule. The preliminary draft calls for the allocation of 100% of the state's emissions allowances through an open, transparent auction. The auction method was chosen over the traditional allowance giveaway to covered sources based largely on the structure of New York's deregulated electricity market. As detailed below, NYDEC's reasoning suggests that an allowance giveaway would effectively provide generators with undue profits and short-change the public.

In New York's deregulated electricity market, generators place bids with the New York Independent System Operator (NYISO) to supply electricity to meet demand. The generator bid prices are typically determined by the costs incurred by the generators to supply electricity. Thus, generator bid amounts under RGGI will include the incremental cost of fuel, labor, and emissions allowances necessary for plant operation. Generators will include in their bids the value of emissions allowances necessary to generate electricity even if the generators received allowances at no cost.

Because the value of the allowances will be included as a cost in the generators' bids to supply electricity, the price of electricity will be the same whether the allowances are purchased or given away at no cost. An allowance giveaway, therefore, would allow generators to substantially increase their revenues (i.e. realize "excess revenues") under the RGGI regime because they could pass on the cost of a commodity they obtained at no charge.

Under New York's proposed RGGI rule, modestly increased costs to electricity consumers under RGGI will be cycled back as energy efficiency investments that will reduce the demand for electricity, thereby taking pressure off electricity prices and the need for new generation in the state. These investments will also complement the carbon cap-and-trade rule by maximizing emissions reductions. In short, the full benefits of the program will accrue to those paying for it, rather than end up increasing the profits of generators through a non-auction allocation method.

The New York draft rule specifies that the 100% allowance auction is to be used for "energy efficiency and clean energy technology purposes", defined to mean the "promotion of energy efficiency measures, promotion of renewable or non-carbon-emitting energy technologies, and stimulation or reward of investment in the development of innovative carbon emissions abatement technologies with significant carbon reduction potential".

In addition to the allocation methodology, the proposed New York rule requires industrial generators (including CHP facilities) that sell less than 10% of their output to the grid to apply to be excluded from the program by applying for a binding permit restriction prior to 1 January 2008. No exclusions would be granted after that date. Emissions attributable to an excluded source would be removed from the starting emissions allowance budget.

Rhode Island

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Rhode Island, which got involved in the RGGI process in February 2007, will probably not have a preliminary RGGI proposal ready for public comment until summer 2007. According to Stephen Majkut, the RI DEP intends to "make every effort to make Rhode Island's rule consistent with RGGI model rule." Though the process is in its infancy, Majkut stated that Rhode Island would like to auction off all of its allowances.

Rhode Island does not view RGGI as a primary vehicle to encourage CHP development given that the Model Rule's 25 MW source threshold is typically larger than most CHP units. The state has instead been working outside of RGGI to enact legislation favorable to CHP. For example, the state legislature went to hearing a couple months ago to enact regulations that would streamline the CHP permitting process to promote installation and use.

Vermont

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The Vermont Department of Environment Conservation's (DEC) Air Pollution Control Division released a "pre-proposal" of the state's RGGI Draft Rule on 9 January 2007 [http://www.anr.state.vt.us/air/htm/RGGI.htm]. The Division is seeking public and stakeholder comments on the pre-proposal draft rule up to 16 April 2007. The NH DEC plans to enter the formal rulemaking process in April/May 2007, and expects to finalize the rule by end 2007.

The Vermont pre-proposal generally follows the RGGI Model Rule but also includes some state-specific provisions, including:

- 100% of the state's CO_2 allowances will be allocated to a consumer benefit or strategic purpose set-aside account.
- The account will be managed by trustees, appointed by the Public Service Board, to provide the maximum long-term benefit to Vermont electric consumers.
- No early reduction CO_2 allowance provisions will be issued.
- Biomass provisions set forth in the Model Rule (e.g. compliance eligibility) will be excluded.

Annex III – Summary of US State CAIR Allocation Plans

Of the 28 states in the CAIR region, 21 states have a draft rule either out for public review/comment or completed.

State	Status	Comment on Allocation and CHP Treatment
Alabama	Final rule completed	All allocations are base on heat input; no special CHP treatment.
Arkansas	Proposal, rule expected to become final in June or July 2007	All allocations output based; output based allocations for CHP.
Connecticut	Proposal	For cogen units and industrial units the allocation is based on heat input, each Phase I and Phase II unit (Phase I: in operation prior to 11/15/1990; Phase II units: in operation on 11/15/1990 or later) will receive allowances based on electrical output. For small CHP units with an efficiency of at least 60% allocations are based on the difference between their NOx emissions and the NOx emissions from an equivalent conventional system providing the same thermal and electric output.
Florida	Final rule completed	Model rule allocations, developed a fuel factor of 1.5 for existing biomass units. Model rule output based allocations for CHP.
Delaware	Final rule completed, but is being challenged	Unit by unit emission limits are based on heat input. Limit NOx emissions from 2009-2011 to 0.15 lb/MMBTU; beginning in 2012 and beyond NOx will be limited to 0.125 lb/MMBTU on a rolling 24-hr basis; no special treatment for CHP.
Georgia	Final rule completed	All allocations are base on heat input; no special CHP treatment.
Illinois	Proposal	Allocations are all output based; model rule output based allocations for CHP; "For a unit that is a combustion turbine or boiler and has equipment used to produce electricity and useful thermal energy (is a CHP unit), then the converted gross output (CGO) will be added to the converted useful thermal energy (CUTE) to determine the total converted gross electrical output for the unit (TCGO)."
Indiana	Final rule completed	Heat input for existing units and electrical output based allocations for new units, but modifies the electrical output to heat conversion factor to provide greater benefit for more efficient units; Output based allocations, different methodologies depending upon system characteristics.
Iowa	Final rule completed	Model rule allocations; model rule output based allocations for CHP.

… continued

State		
Kentucky	Proposal, expected to be submitted to EPA within the week of March 26-30 2007	Allocations based on fuel adjusted heat input; no special treatment for CHP.
Louisiana	NOx proposal, SO_2 final rule completed	Model rule allocations, fuel adjusted heat input for existing units and electrical output for new units; no special treatment for CHP.
Maryland	Staff is currently working on an implementation plan	Released emergency regulations with unit by unit annual tonnage limits; Healthy Air Act (HAA) has been approved, working on an implementation plan.
Massachusetts	Proposal	Allocations are all output based, annual updating of baselines; changed CHP applicability. CHP units are regulated if they burn more than 50% fossil fuels. The CHP systems efficiency must be at least 60%; ozone season allocations = ([NOx conventional] – [NOx CHP system]) / (2,000 lbs/ton). Where:[NOx conventional] = (kWh * (3,412 Btu/kWh) / 0.34 + Heat Out / 0.8) / 1,000,000 * (0.15 lbs NOx/MMBtu); [NOx CHP system] = Btu In / 1,000,000 * NOx Rate.
Michigan	Proposal	Allocations based on fuel adjusted heat input; no special treatment for CHP.
Minnesota	Proposal	Model rule allocations; model rule output based allocations for CHP.
Mississippi	Final rule completed	Model rule allocations; model rule output based allocations for CHP.
Missouri	Final rule completed, expected to become effective in the summer of 2007	Model rule allocations; model rule output based allocations for CHP.
New York	Internal proposal	Plan on allocating all allowances based on heat input.
New Jersey	Proposal	Allocations are all output based; CHP units receive output based allocations and are considered to be regulated units.
North Carolina	Final rule completed	Model rule allocations; model rule output based allocations for CHP.
Ohio	Proposal, should be submitted to the EPA within the next month	Model rule allocations; model rule output based allocations for CHP.
Pennsylvania	Final rule completed	Allocations output based; model rule output based allocations for CHP.
South Carolina	Final rule completed	All allocations based on heat input - fuel adjusted coal x 100%, all others x 60%; no special treatment for CHP.
Tennessee	Final rule completed	Model rule allocations; model rule output based allocations for CHP

… continued

State	Status	Comment on Allocation and CHP Treatment
Texas	Final rule completed	For existing units allocations are based on heat input from (2009-2015). In 2016, allocations for existing units will still be based on heat input but will use the following fuel adjustments: =coal x 90%, natural gas x 50%, and all others x 30%. Beginning in the 2015 control period, units that began operation on or after 1/1/01 that operated each year for five consecutive years will no longer be eligible for allocations from the new unit set-aside of 9.5%. In 2016, allowances for new units will be allocated based on its gross electrical output (from the highest 5 out of 7 previous years). Model rule output based allocations for CHP.
Virginia	Final rule completed	Model rule allocations; model rule output based allocations for CHP.
West Virginia	Final rule completed	Model rule allocations; model rule output based allocations for CHP.
Wisconsin	Final rule completed	All allocations output based; All units: (Useful output / 3.4 MMBtu/MWh) + (Electrical Generation Output).
District of Columbia	Internal proposal, has already been submitted to the EPA	Unknown allocations; plans on submitting an abbreviated SIP.

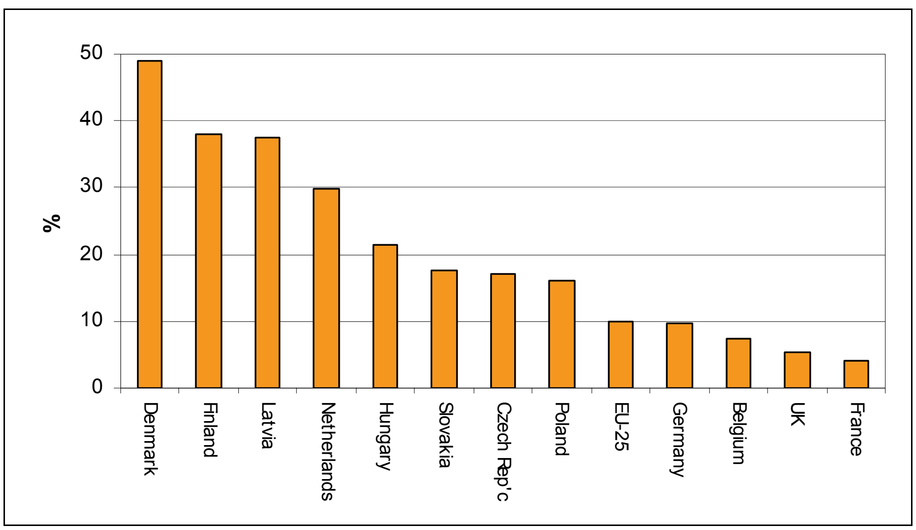
Annex IV – CHP Capacity Data

CHP capacity and market share data is available for a relatively small number of countries only. Where it is collected, it is done so in different ways, making it hard to draw direct comparisons between countries. There are three main series presented here, based on three sources of information:

- Eurostat is the statistics agency of the EU. It is charged with collecting data on a standardized basis from each member state, in a way which ensures that each country can be properly compared with others.
- The World Alliance for Decentralized Energy (WADE), which has sought to collect capacity and market share data from major countries on an annual basis since 2002. WADE has not attempted to standardize the data. Figure 5 below shows the CHP electric output as a share of total national output (data for capacity share is not given because this tends to be less meaningful; for example, in some countries, load factors of some large district energy CHP plants can be relatively low, leading to unrepresentatively high CHP capacity shares).
- Tom Casten and Marty Collins, formerly of US-based Primary Energy, produced state-by-state data on CHP shares of overall generation which was subsequently published in 'Optimizing Future Heat and Power Generation' in May 2004. The data is based on CHP plants built before PURPA, which created definitions for FERC qualified CHP plants and small power plants using alternate fuels that generate heat and power.

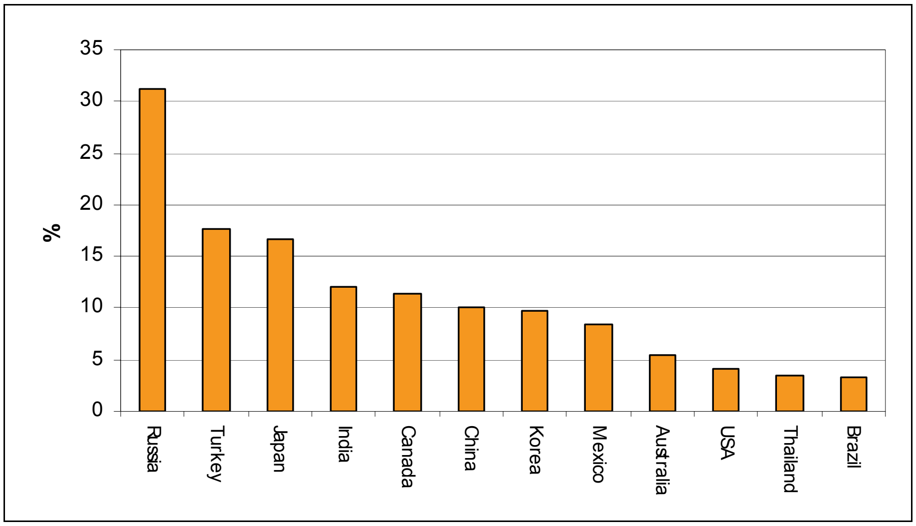
Figure 5 below shows the Eurostat data for the EU, while figure 6 summarizes the WADE data and figure 7 the US data for selected states.

FIGURE 5
CHP SHARES OF TOTAL GENERATION FOR SELECTED EU COUNTRIES - %



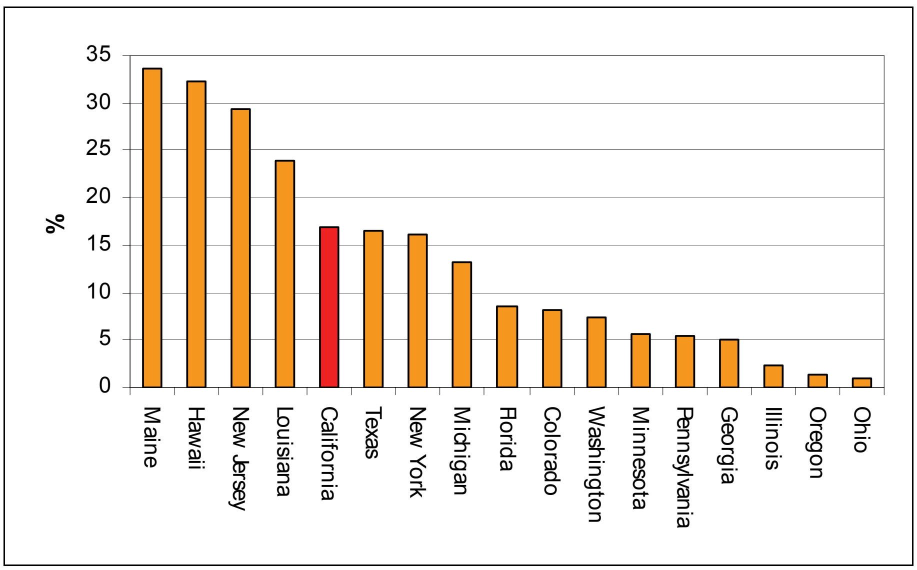
EUROSTAT. 2004. STANDARDISED DATA.

FIGURE 6
CHP SHARES OF TOTAL GENERATION FOR SELECTED NON-EU COUNTRIES - %



WADE. 2006. NON-STANDARDISED DATA.

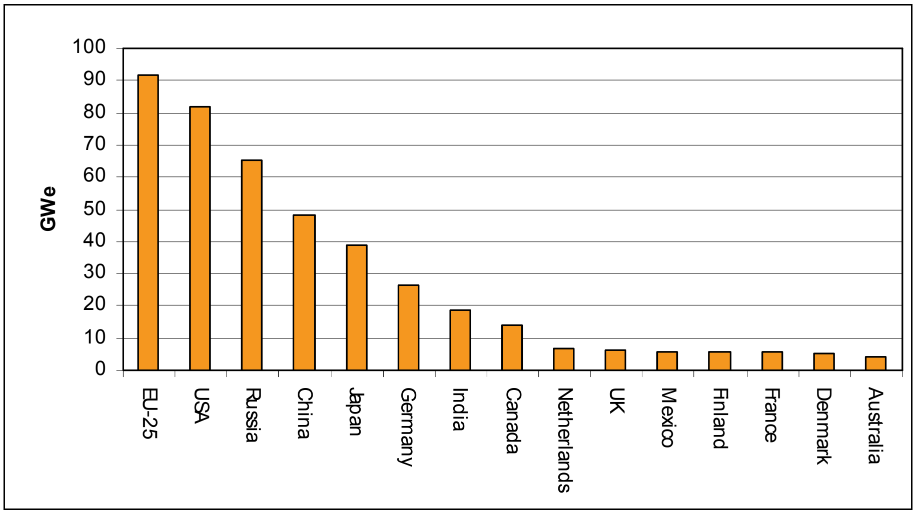
FIGURE 7
CHP SHARES OF TOTAL GENERATION FOR SELECTED US STATES - %



CASTEN/COLLINS: OPTIMISING FUTURE HEAT AND POWER GENERATION, 2004. COGENWORKS.COM, 2007.

Finally, figure 8 below presents a compilation of CHP absolute capacity data from the two international sources.

FIGURE 8
CHP CAPACITY DATA - GWE



EUROSTAT 2004. WADE 2006. NON-STANDARDISED DATA

CHP Data – Key Conclusions

- While the installed capacity of CHP in the US appears to be impressive (Figure 8), more meaningful data on CHP as a share of generation shows it to be a below average performer on an international basis (Figure 6).
- Within the US, there is a wide variety of CHP shares between states. California is an above average performer.
- A handful of EU countries show what can be achieved. The Netherlands, Finland and Denmark all have significant CHP market shares based on a background of policy and market incentives geared towards delivering an energy supply system that delivers high efficiency within a context of a fully competitive market economy (only the Danish example can be characterized as one based on subsidy of district heating systems; the Dutch and Finnish examples are based on market mechanisms designed to reflect the efficiency benefits of industrial and commercial sector CHP). In short, very high levels of CHP are certainly not inconsistent with productive and efficient economic activity.

References

[i] Unless otherwise noted, all efficiency figures presented in this document refer to Lower Heating Value, or “LHV”, of the fuel input.

[ii] Regional Greenhouse Gas Initiative (RGGI), "RGGI Model Rule," (available at http://www.rggi.org/modelrule.htm), January 5, 2007, with corrections.

[iii] RGGI, "Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI): Evaluating Market Dynamics, Monitoring Options, and Possible Mitigation Mechanisms," (http://www.rggi.org/emisleak.htm) March 14, 2007.

[iv] RGGI, "Potential Emissions Leakage," (http://www.rggi.org/emisleak.htm) March 14, 2007, p. 42.

[v] From RGGI, "Potential Emissions Leakage," (http://www.rggi.org/emisleak.htm) March 14, 2007, p. 30.

[vi] The RGGI draft database (available at http://www.rggi.org/documents.htm) on units to be covered by the Initiative remains incomplete in terms of identifying CHP units. We have used a list generated from EEA's Oak Ridge National Laboratory database to estimate the CHP in the RGGI region.

[vii] Energy and Environmental Analysis, *Analysis of Output-Based Allocation of Emission Trading Allowance*, (submitted to the U.S. Combined Heat and Power Association), June 2003.

[viii] The ozone season is defined as May 1 to September 30 of each year.

[ix] EPA’s rationale for issuance of the FIP prior to the September 2006 deadline for state CAIR SIPs is that states failed to submit SIPs to address interstate transport following EPA’s adoption of the ozone and $PM_{2.5}$ standards in 1997 and that the FIP will insure that CAIR reductions occur according to EPA’s timeframe.

[x] These allocations can be found at: http://www.epa.gov/airmarkets/cair/noda/index.html.

[xi] Most significantly, a group of corporations - including DuPont, Alcoa, General Electric, and Duke Energy - formed the U.S. Climate Action Partnership ("USCAP"), issued a detailed set of recommendations, and began urging Congress to pass cap-and-trade legislation. Even more businesses, such as Wal-Mart, have joined the discussion by praising USCAP's work and by voluntarily adopting their own climate change goals. With industry, environmental groups, and Congress collaborating to find a solution, USCAP represents a noteworthy development for climate change policy in the United States.

[xii] Case No. 05-1120.

CERTIFICATE OF SERVICE

I, Karen Terranova hereby certify that I have on this date caused the attached **Notice of Ex Parte Communication** in R.06-04-009 to be served to all known parties by either United States mail or electronic mail, to each party named in the official attached service list obtained from the Commission's website, attached hereto, and pursuant to the Commission's Rules of Practice and Procedure.

Dated June 4, 2007 at San Francisco, California.

Karen Terranova

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